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

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

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 2010/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 2010/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 Jason M. Johnson		06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, 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 Andrew B. Reis	03 Signature Andrew B. Reis	04 Date Signed *(Mo, Da, Yr)* 04/15/2011
02 Title Assistant Controller		

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

Name of Respondent	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 2010/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

GENERAL INFORMATION

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

Andrew B. Reis, Assistant Controller
1 Riverside Plaza
Columbus, OH 43215

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and 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 2010/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.

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 2010/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.		
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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 2010/Q4

OFFICERS

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

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

Executive Compensation Table

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

Name and Principal Position (a)	Salary ($)(1) (b)	Bonus ($) (c)	Stock Awards ($)(2) (d)	Option Awards ($) (e)	Non-Equity Incentive Plan Compensation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(4) (g)	All Other Compensation Earnings ($)(5) (h)	Total ($) (i)
Michael G. Morris — Chairman of the Board and Chief Executive Officer	1,270,442	—	5,321,150	—	1,579,785	341,768	512,969	9,026,114
Brian X. Tierney — Executive Vice President and Chief Financial Officer	467,365	—	2,703,635	—	425,000	180,228	29,456	3,805,684
Robert P. Powers — President – AEP Utilities	523,844	—	2,763,712	—	420,961	511,871	34,569	4,254,957
Nicholas K. Akins (6) — President	515,056	—	2,429,269	—	365,000	114,757	35,161	3,459,243
Carl L. English — Vice Chairman	563,998	—	1,805,415	—	450,000	74,119	35,475	2,929,007
Venita McCellon-Allen (7) — President and COO SWEPCo	410,919	—	2,342,483	—	283,780	88,287	49,564	3,175,033

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

(2) The amounts reported in this column reflect the total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2010 for a discussion of the relevant assumptions used in calculating these amounts. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0% 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 is equal to 200% of the target award, 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 or reinvestment date.

The 2010 amounts also include 41,380 restricted stock units awarded in August 2010 to Morris. Akins, Powers, and Tierney and Ms. McCellon-Allen. The maximum amount payable for the restricted stock units is equal to the award plus an amount equal to reinvested dividends multiplied by the percentage increase in AEP's stock price from the grant or reinvestment date.

(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 annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2010, 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 Company contributions to the Company's Retirement Savings Plan and the Company's Supplemental Retirement Savings Plan.

For Mr. Morris, the amount shown for 2010 includes the aggregate incremental cost associated with his personal use of Company-provided aircraft of $444,737. This amount is the incremental cost to the Company for his personal use of Company-provided aircraft, including all operating costs such as fuel, a maintenance reserve for the hours flown, 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 to attend outside board meetings for the public companies at which he serves as an outside director. In 2009, the HR Committee generally 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.

(6) Mr. Akins was appointed President of the Company effective January 1, 2011. He was previously Executive Vice President-Generation.

(7) Ms. McCellon-Allen was Executive Vice President of AEP through June 30, 2010. In a corporate realignment, she became President and Chief Operating Officer of Southwestern Electric Power Company, one of AEP's public utility subsidiaries. She currently is not an executive officer of AEP.

All Other Compensation 2010

Type	**Michael G. Morris**	**Brian X. Tierney**	**Robert P. Powers**	**Nicholas K. Akins**	**Carl L. English**	**Venita McCellon-Allen**
Retirement Savings Plan Match	4,327	7,590	10,727	7,678	11,025	10,628
Supplemental Retirement Savings Plan Match	52,614	13,316	12,748	15,367	14,250	7,787
Director Life and Accident Insurance	741	-	-	-	-	-
Financial Counseling and Tax Preparation	10,550	8,550	11,094	12,116	9,800	11,149
Personal Use of Company Aircraft	444,737	-	-	-	-	-
Health & Wellness Program Incentives	-	-	-	-	400	-
Relocation Payment	-	-	-	-	-	20,000

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, Chief Financial Officer	Columbus, Ohio
5	and Vice President	
6		
7	Carl L. English, Vice President	Columbus, Ohio
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9	Robert P. Powers, Vice President	Columbus, Ohio
10		
11	Susan Tomasky, Vice President	Columbus, Ohio
12		
13	Dennis E. Welch, Vice President	Columbus, Ohio
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15	Nicholas K. Akins, Vice President	Columbus, Ohio
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17	Michael D. Miller, Secretary	Columbus, Ohio
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19	Barbara D. Radous, Vice President	Columbus, Ohio
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24	Note: The Respondent does not have an Executive Committee.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PJM Intercompany L.L.C. - Attachment H-14	ER08-1329
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20100525-5107	05/25/2010	ER09-1200	AEP PJM OATT Formula Update	PJM OATT Attach H-14
2					
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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 2010/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	Not Applicable			
2				
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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 March 22, 2010	Village of Middleport, Meigs County, OH	Twenty-Five (25) Year Franchise Renewal expiring March 22, 2035	None
Renewed on June 23, 2010	Village of Cherry Fork, Adams County, OH	Twenty-Five (25) Year Franchise Renewal expiring June 23, 2035	None
Renewed on August 2, 2010	Village of Aberdeen	Twenty-Five (25) Year Franchise Renewal expiring August 2, 2035	None

2. None

3. None

4. None

5. None

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

   $150M Floating Senior Notes, Series A, due March 16, 2012

7. None

8. CSP employees represented by IBEW Local #1466 were provided with a 2% general wage increase

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

10. None

11. (Reserved)

12. Not Used

13. Susan E. Higginson resigned as Assistant Controller effective February 1, 2010
Richard E. Munczinski resigned as Director and Vice President effective January 28, 2010
Barbara D. Radous elected as Director and Vice President effective January 28, 2010
David L. Celona resigned as Vice President-External Affairs effective April 21, 2010
Venita McCellon-Allen resigned as Director, Vice Chairman of the Board and Vice President effective May 31, 2010
John B. Keane resigned as Director and Secretary effective June 30, 2010
Julie Williams elected as Assistant Controller effective May 18, 2010

Edward M. Mowrer resigned as Vice President – Distribution Region Operations effective September 30, 2010
Stephen W. Burge resigned as Vice President – Generation Assets effective August 31, 2010
D. Michael Miller elected Director and Secretary effective July 1, 2010
Thomas L. Froehle elected as Vice President – External Affairs effective September 20, 2010
Thomas L. Kirkpatrick elected as Vice President – Distribution Region Operations effective September 20, 2010
Mark A. Peifer elected as Vice President – Generation Assets effective October 15, 2010
Andrew B. Reis elected as Assistant Controller effective December 14, 2010

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 2010/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	5,405,288,595	5,253,876,362
3	Construction Work in Progress (107)	200-201	172,753,317	154,927,997
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,578,041,912	5,408,804,359
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,146,718,452	2,045,318,829
6	Net Utility Plant (Enter Total of line 4 less 5)		3,431,323,460	3,363,485,530
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)		3,431,323,460	3,363,485,530
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	15,394,662
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,257,970	3,056,815
20	Investments in Associated Companies (123)		430,000	430,000
21	Investment in Subsidiary Companies (123.1)	224-225	-3,253,751	-1,483,512
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	11,621,595	14,539,865
24	Other Investments (124)		12,268,846	12,368,010
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)		22,082,408	23,881,702
31	Long-Term Portion of Derivative Assets – Hedges (176)		6,854	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		55,292,644	62,073,912
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		508,677	1,095,653
36	Special Deposits (132-134)		17,022,812	31,024,169
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		49,508,271	21,199,052
41	Other Accounts Receivable (143)		12,670,852	16,972,690
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,582,027	3,481,442
43	Notes Receivable from Associated Companies (145)		49,740,728	0
44	Accounts Receivable from Assoc. Companies (146)		63,368,406	25,172,755
45	Fuel Stock (151)	227	70,686,727	72,012,385
46	Fuel Stock Expenses Undistributed (152)	227	2,195,024	2,146,159
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	39,366,858	37,341,838
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	39,825,596	41,112,209

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 2010/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		11,621,595	14,539,865
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		17,794,269	20,947,059
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,699,575	1,196,442
60	Rents Receivable (172)		673,195	828,991
61	Accrued Utility Revenues (173)		32,821,085	11,845,481
62	Miscellaneous Current and Accrued Assets (174)		1,849,442	1,038,015
63	Derivative Instrument Assets (175)		45,634,482	57,240,579
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		22,082,408	23,881,702
65	Derivative Instrument Assets - Hedges (176)		228,599	983,993
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		6,854	0
67	Total Current and Accrued Assets (Lines 34 through 66)		410,301,714	300,254,461
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		7,905,467	6,693,845
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	307,764,735	334,715,592
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,563	1,307
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	124,586,654	109,835,770
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)		8,613,391	9,356,932
82	Accumulated Deferred Income Taxes (190)	234	136,598,493	118,960,211
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		585,472,303	579,563,657
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,482,390,121	4,305,377,560

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 2010/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	322,920,065	322,772,227
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	913,577,710	786,073,173
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,134,800	2,064,800
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-51,335,895	-49,993,531
16	Total Proprietary Capital (lines 2 through 15)		1,486,215,163	1,359,835,152
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	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)		3,914,667	6,352,416
24	Total Long-Term Debt (lines 18 through 23)		1,438,830,333	1,536,392,584
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		7,964,129	2,238,573
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		59,997	52,893
29	Accumulated Provision for Pensions and Benefits (228.3)		119,951,759	122,486,763
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	3,447,229
31	Accumulated Provision for Rate Refunds (229)		50,000,000	0
32	Long-Term Portion of Derivative Instrument Liabilities		6,222,940	10,272,145
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		170	40,700
34	Asset Retirement Obligations (230)		50,327,920	39,349,106
35	Total Other Noncurrent Liabilities (lines 26 through 34)		234,526,915	177,887,409
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		98,522,624	95,641,617
39	Notes Payable to Associated Companies (233)		0	28,793,049
40	Accounts Payable to Associated Companies (234)		79,624,725	82,843,693
41	Customer Deposits (235)		29,441,222	27,910,876
42	Taxes Accrued (236)	262-263	212,557,398	167,830,218
43	Interest Accrued (237)		24,752,229	23,521,360
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		788,024	945,526
48	Miscellaneous Current and Accrued Liabilities (242)		37,250,421	37,019,876
49	Obligations Under Capital Leases-Current (243)		3,763,536	2,124,146
50	Derivative Instrument Liabilities (244)		21,771,371	21,570,096
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		6,222,940	10,272,145
52	Derivative Instrument Liabilities - Hedges (245)		419,009	1,794,275
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		170	40,700
54	Total Current and Accrued Liabilities (lines 37 through 53)		502,667,449	479,681,887
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		275,637	276,152
57	Accumulated Deferred Investment Tax Credits (255)	266-267	14,787,360	16,832,959
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	20,391,576	19,710,055
60	Other Regulatory Liabilities (254)	278	13,617,207	29,881,704
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	33,077,639	19,682,408
63	Accum. Deferred Income Taxes-Other Property (282)		616,195,586	534,670,941
64	Accum. Deferred Income Taxes-Other (283)		121,805,256	130,526,309
65	Total Deferred Credits (lines 56 through 64)		820,150,261	751,580,528
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,482,390,121	4,305,377,560

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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	2,218,739,662	2,057,100,425		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,314,806,972	1,095,211,853		
5	Maintenance Expenses (402)	320-323	108,388,702	126,441,018		
6	Depreciation Expense (403)	336-337	134,694,030	126,946,745		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	4,337,300	2,676,327		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	9,644,751	11,690,325		
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)		3,071,470	3,133,858		
13	(Less) Regulatory Credits (407.4)		307,352	92,681		
14	Taxes Other Than Income Taxes (408.1)	262-263	187,260,200	175,068,961		
15	Income Taxes - Federal (409.1)	262-263	57,462,289	19,276,023		
16	- Other (409.1)	262-263	4,522,986	618,297		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	232,541,825	315,856,139		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	152,716,154	175,127,692		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,045,599	-1,980,124		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		3,722,826	65,741		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,764,178	1,358,946		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,900,702,772	1,701,012,254		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		318,036,890	356,088,171		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,218,739,662	2,057,100,425					2
						3
1,314,806,972	1,095,211,853					4
108,388,702	126,441,018					5
134,694,030	126,946,745					6
4,337,300	2,676,327					7
9,644,751	11,690,325					8
						9
						10
						11
3,071,470	3,133,858					12
307,352	92,681					13
187,260,200	175,068,961					14
57,462,289	19,276,023					15
4,522,986	618,297					16
232,541,825	315,856,139					17
152,716,154	175,127,692					18
-2,045,599	-1,980,124					19
						20
						21
3,722,826	65,741					22
						23
2,764,178	1,358,946					24
1,900,702,772	1,701,012,254					25
318,036,890	356,088,171					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 2010/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)		318,036,890	356,088,171		
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)		4,725	4,364		
34	(Less) Expenses of Nonutility Operations (417.1)		3,463			
35	Nonoperating Rental Income (418)		413,300	422,929		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	70,000	297,299		
37	Interest and Dividend Income (419)		907,788	801,959		
38	Allowance for Other Funds Used During Construction (419.1)		2,071,722	3,381,744		
39	Miscellaneous Nonoperating Income (421)		9,112,910	10,087,139		
40	Gain on Disposition of Property (421.1)		526	11,870		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		12,577,508	15,007,304		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,235,687	23,535		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		6,601,505	4,978,334		
46	Life Insurance (426.2)					
47	Penalties (426.3)		2,754	64,326		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,065,646	726,798		
49	Other Deductions (426.5)		12,194,477	22,257,419		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		22,100,069	28,050,412		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263		80,000		
53	Income Taxes-Federal (409.2)	262-263	-4,220,622	-6,234,256		
54	Income Taxes-Other (409.2)	262-263	98,001	288,175		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,564,257	3,146,371		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	7,566,520	12,143,663		
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)		-8,124,884	-14,863,373		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-1,397,677	1,820,265		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		82,229,719	79,206,255		
63	Amort. of Debt Disc. and Expense (428)		1,862,634	1,841,488		
64	Amortization of Loss on Reaquired Debt (428.1)		743,541	743,496		
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)		978,639	5,974,022		
68	Other Interest Expense (431)		2,913,400	4,450,067		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,311,095	5,967,995		
70	Net Interest Charges (Total of lines 62 thru 69)		86,416,838	86,247,333		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		230,222,375	271,661,103		
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)		230,222,375	271,661,103		

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 2010/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		786,073,173	664,555,475
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	-147,838	(157,440)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-147,838	(157,440)
16	Balance Transferred from Income (Account 433 less Account 418.1)		230,152,375	271,363,804
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		-102,500,000	(150,000,000)
32	Noncash Dividend of Property to Parent			(8,123,156)
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-102,500,000	(158,123,156)
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)		913,577,710	786,073,173
	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 2010/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)		913,577,710	786,073,173
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		2,064,800	10,201,991
50	Equity in Earnings for Year (Credit) (Account 418.1)		70,000	297,299
51	(Less) Dividends Received (Debit)			
52	Transfer to Acct 216.0 (Merger of Colomet, Inc.)			(8,434,490)
53	Balance-End of Year (Total lines 49 thru 52)		2,134,800	2,064,800

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 2010/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)	230,222,375	271,661,103
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	148,676,081	141,313,397
5	Amortization of Regulatory Debits and Credits (Net)	2,764,118	3,041,177
6	Customer Deposits	1,530,346	-2,234,370
7	Carrying Costs	-8,166,281	-7,655,770
8	Deferred Income Taxes (Net)	75,823,408	131,731,155
9	Investment Tax Credit Adjustment (Net)	-2,045,599	-1,980,124
10	Net (Increase) Decrease in Receivables	-53,625,496	47,505,234
11	Net (Increase) Decrease in Inventory	1,236,017	-37,714,812
12	Net (Increase) Decrease in Allowances Inventory	1,286,613	-4,639,713
13	Net Increase (Decrease) in Payables and Accrued Expenses	61,041,259	-77,071,632
14	Net (Increase) Decrease in Other Regulatory Assets	520,025	-20,076,262
15	Net Increase (Decrease) in Other Regulatory Liabilities	-15,144,570	17,143,899
16	(Less) Allowance for Other Funds Used During Construction	2,071,722	3,381,744
17	(Less) Undistributed Earnings from Subsidiary Companies	70,000	297,299
18	Other (provide details in footnote):	-8,185,164	-14,159,782
19	Deferred Property Taxes	-12,463,111	-7,364,449
20	Over / Under Recovered Fuel, Net	21,792,332	-36,028,133
21	Provision for 2009 Significantly Excessive Earnings Test	42,683,000	
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	485,803,631	399,791,875
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-237,939,237	-305,927,555
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	-2,071,722	-3,381,744
31	Acquired Assets	-741,802	-232,002
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-236,609,317	-302,777,813
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	5,106,558	823,455
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 Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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	14,392	27,659
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	gridSMART Reimbusement Allocation	12,666,935	
54	(Increase) Decrease in Other Special Deposits	13,889,698	16,150,341
55	Notes Receivable from Associated Companies	-49,740,728	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-254,672,462	-285,776,358
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	92,245,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs	-556,619	-1,084,548
66	Net Increase in Short-Term Debt (c)		
67	Proceeds from Acquired Assets Subject to Capital Lease	131,523	219,884
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	149,574,904	91,380,336
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-250,000,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-28,793,049	-55,362,805
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-102,500,000	-150,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-231,718,145	-113,982,469
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-586,976	33,048
87			
88	Cash and Cash Equivalents at Beginning of Period	1,095,653	1,062,605
89			
90	Cash and Cash Equivalents at End of period	508,677	1,095,653

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

	2010 Cash Flow Incr / (Decr)	2009 Cash Flow Incr / (Decr)
Utility Plant, Net	(4,710,815)	(6,251,021)
Property and Investments, Net	285,927	2,891,813
Margin Deposits	111,659	(1,261,303)
Mark-to-Market of Risk Management Contracts	11,807,372	(4,785,818)
Prepayments	590,533	2,774,792
Accrued Utility Revenues, Net	(20,975,604)	6,513,132
Miscellaneous Current and Accr Assets	(875,219)	194,821
Unamortized Debt Expense	1,443,087	2,566,598
Other Deferred Debits, Net	(1,472,221)	(4,014,072)
Other Comprehensive Income, Net	(377,646)	1,199,400
Unamortized Discount/Premium on Long-Term Debt	339,659	553,954
Accumulated Provisions - Misc	4,226,857	3,226,140
Current and Accrued Liabilities, Net	(1,367,438)	(6,125,649)
Other Deferred Credits, Net	2,788,685	(11,642,569)
Total	**(8,185,164)**	**(14,159,782)**

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

	2010 Cash Flow Incr / (Decr)	2009 Cash Flow Incr / (Decr)
Sale of meters to affilated operating companies	1,935,714	317,209
Sale of transformers to affilated operating companies	2,334,193	506,246
Sale of Centrifugal Pump - Arlington Valley LLC	300,639	-
Proceeds from acquired assets subject to Operating Lease	536,012	-
Total	**5,106,558**	**823,455**

NOTES TO FINANCIAL STATEMENTS

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

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. 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.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Term	Meaning
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KGPCo, KPCo, OPCo and WPCo which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric utility 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.

In October 2010, CSPCo and OPCo filed with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until the PUCO approves new rates, terms and conditions for the merged company. In January 2011, CSPCo and OPCo filed with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo effective October 2011.

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. 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 December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management’s ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If CSPCo experiences decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company’s MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

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

AEPSC conducts power, gas, coal and emission allowance risk management activities on 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 state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. 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 aligning generation/power supply rates over time with 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.

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 unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, 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, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents on the 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

	2010	2009
For the Years Ended December 31,	**(in thousands)**	
Cash Was Paid for:		
Interest (Net of Capitalized Amounts)	$ 85,242	$ 94,136
Income Taxes (Net of Refunds)	36,618	46,766
Noncash Acquisitions Under Capital Leases	9,632	892
At December 31,		
Noncash Construction Expenditures Included in Accounts Receivable	9,260	-
Noncash Construction Expenditures Included in Accounts Payable	14,229	31,106

Special Deposits

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

Inventory

Fossil fuel and materials and supplies inventories are generally 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 on a daily basis, excluding receivables from risk management activities, through purchase agreements with CSPCo. See “Sale of Receivables – AEP Credit” section of Note 11 for additional information.

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, 2010 or 2009.

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 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 sale of emission allowances held speculatively are recorded in Miscellaneous Nonoperating Income and Other Deductions, respectively. Purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows except speculative allowance transactions which are reported in Investing Activities.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original purchase cost. 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. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet 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.

Nonregulated

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

Investment in Subsidiary Companies

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.

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 such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchanges 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 to estimate the fair value of the underlying investments held in the benefit plan. 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.

Assets in the benefits trust and Special Deposits are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. 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.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the PUCO’s review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the PUCO. On a routine basis, the PUCO reviews and/or audits 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. Beginning in 2009, changes in fuel costs, including purchased power for CSPCo are reflected in rates through FAC phase-in plans.

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 include unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. 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 arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expense. All other non-trading derivative purchases are recorded net in revenues.

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 on 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, as well as 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. 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 transaction on its income statements. 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 agents 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.

Government Grants

In 2010, CSPCo received final approval for a federal stimulus grant for the gridSMART® demonstration program. CSPCo is reimbursed for allowable costs incurred during the billing period. These reimbursements result in the reduction of Operation Expenses and Maintenance Expenses on the statements of income or Construction Work in Progress on the balance sheet.

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. 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 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	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 Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

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

Comprehensive Income (Loss)

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

Adjustments to Sale of Receivables Disclosure

In the “Sale of Receivables – AEP Credit” section of Note 11, the disclosure was expanded to reflect certain prior period amounts related to the sale of receivables that were not previously disclosed. These omissions were not material to the financial statements and had no impact on previously reported net income, changes in shareholders’ equity, financial position or cash flows.

Adjustments to Benefit Plans Footnote

In Note 5 – Benefit Plans, the disclosure was expanded to reflect disclosure requirements based on participation in the AEP System. These omissions were not material to the financial statements and had no impact on previously reported net income, changes in shareholder’s equity, financial position or cash flows.

2. RATE MATTERS

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

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved CSPCo’s ESP which established rates at the start of the April 2009 billing cycle. The ESP is in effect through 2011. The order also limited annual 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 provided a FAC for the three-year period of the ESP. The FAC was phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC is subject to quarterly true-ups, annual accounting audits and prudency reviews. The order allowed CSPCo to defer any unrecovered FAC costs resulting from the annual caps and accrued associated carrying charges at CSPCo's weighted average cost of capital. Any 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. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below.

Discussed below are the significant 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 alleged retroactive ratemaking, 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. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMART® 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 pending.

In April 2010, the Industrial Energy Users-Ohio filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings under the Significantly Excessive Earnings Test (SEET). If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's return on common equity was 20.84% including off-system sales margins. In January 2011, the PUCO issued an order that determined a return on common equity for 2009 in excess of 17.6% would be significantly excessive. The PUCO determined relevant CSPCo earnings, excluding off-system sales margins, to be 19.73%, which exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million ($28 million, net of tax) of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis which began with the first billing cycle in February 2011 through December 2011. Several parties, including CSPCo, have filed requests for rehearing with the PUCO, which remain pending. CSPCo and OPCo are required to file their 2010 SEET filing with the PUCO in 2011. Based upon the approach in the PUCO 2009 order, management does not currently believe that there are significantly excessive earnings in 2010.

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

Proposed January 2012 – May 2014 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing on a combined company basis for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio and other matters. The SSO presents redesigned generation rates by customer class. Customer class rates individually vary, but on average, customers will experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC.

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 approved by the PUCO and was effective from January 2009 through September 2009. 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. The Industrial Energy Users-Ohio, CSPCo and OPCo filed Notices of Appeal regarding aspects of this decision with the Supreme Court of Ohio. A hearing at the Supreme Court of Ohio was held in February 2011. Through September 2009, the last month of the interim arrangement, CSPCo had $30 million of deferred FAC related to the interim arrangement including recognized carrying charges, excluding $1 million of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo’s and OPCo’s FAC phase-in deferral balances. See “Ohio Electric Security Plan Filings” section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. 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 deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's ESP proceeding and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP order.

As of December 31, 2010, CSPCo has incurred $38 million in EDR costs including carrying costs. Of these costs, CSPCo has collected $35 million through the EDR, which CSPCo began collecting in January 2010. The remaining $3 million for CSPCo is recorded as an EDR regulatory asset. If CSPCo is not ultimately permitted to recover its deferrals or is required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million for CSPCo effective September 2010. The implementation of the rider will likely not impact cash flows since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings, but will increase the ESP phase-in plan deferrals associated with the FAC.

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. Through December 31, 2010, 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 any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (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. 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 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 asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

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.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2010 was $32 million. CSPCo's reserve balance at December 31, 2010 was $5.6 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC. CSPCo's portion of potential refund payments is $3.5 million and its potential payments to be received are $1.8 million.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies 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. In June 2009, 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 generally 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. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought 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 and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

In October 2010, a settlement agreement was approved by the FERC which resulted in a $51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately $7 million is being collected from nonaffiliated customers within PJM. Prior to November 2010, the remaining $44 million was billed to the AEP East companies and was generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income was not directly affected. Beginning in November 2010, AEP East companies, KGPCo and WPCo, which are parties to the modified TA, allocate revenue and expenses on different methodologies and will affect net income. See "Modification of the Transmission Agreement" above.

The settlement also results in an additional $30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining $26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be 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. In May 2010, the second annual update was filed with the FERC to decrease the revenue requirement by $58 million for service as of July 2010. Approximately $8 million of the decrease will be refunded to nonaffiliated customers within PJM.

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 KPCo's 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. In June 2010, the KPSC approved a settlement agreement in KPCo's base rate filing which set new base rates effective July 2010 but excluded consideration of this issue.

PJM/MISO Market Flow Calculation Settlement Adjustments

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 dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2010**	**December 31, 2009**	**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			
Line Extension Carrying Costs	$ 33,709	$ 26,590	
Customer Choice Deferrals	29,716	28,781	
Storm Related Costs	19,122	17,014	
Acquisition of Monongahela Power	7,929	10,282	
Economic Development Rider	3,057	-	
Other Regulatory Assets Not Yet Being Recovered	287	1,422	
Regulatory Assets Currently Not Earning a Return			
Acquisition of Monongahela Power	4,052	-	
Peak Demand Reduction/Energy Efficiency	- (a)	4,071	
Other Regulatory Assets Not Yet Being Recovered	43	17	
Total Regulatory Assets Not Yet Being Recovered	97,915	88,177	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	16,031	36,982	1year
RTO Formation/Integration Costs	2,420	2,692	9 years
Economic Development Rider	710	10,209	1 year
Acquisition of Monongahela Power	504	2,861	1 year
Other Regulatory Assets Being Recovered	382	-	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	173,755	175,024	13 years
Income Tax Assets	5,337	13,674	25 years
Enhanced Service Reliability Plan	2,990	2,061	2 years
Postemployment Benefits	2,909	3,036	4 years
Unrealized Loss on Forward Commitments	2,591	-	1 year
Energy Efficiency/Peak Demand Reduction	2,221 (a)	-	2 years
Total Regulatory Assets Being Recovered	209,850	246,539	
Total FERC Account 182.3 Regulatory Assets	$ 307,765	$ 334,716	

	December 31, 2010	December 31, 2009	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^{SM} Costs	$ 6,182	$ 7,477	
Low Income Customers/Economic Recovery	2,260	2,351	
Other Regulatory Liabilities Not Yet Being Recovered	1,817	1,823	
Total Regulatory Liabilities Not Yet Being Paid	10,259	11,651	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Transmission Cost Recovery Rider	786	14,811	1 year
Other Regulatory Liabilities Being Paid	336	377	various
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities	2,236	3,043	25 years
Total Regulatory Liabilities Being Paid	3,358	18,231	
Total FERC Account 254 Regulatory Liabilities	$ 13,617	$ 29,882	

(a) Recovery of regulatory asset granted during 2010.

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. The forecasted construction expenditures excluding AFUDC and capitalized interest for 2011 are $187 million. CSPCo purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes the actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 254.1	$ 426.9	$ 323.2	$ 497.5	$ 1,501.7
Energy and Capacity Purchase Contracts (b)	5.3	7.1	2.7	16.9	32.0
Total	$ 259.4	$ 434.0	$ 325.9	$ 514.4	$ 1,533.7

(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.

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 and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following two liability trials, the jury found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. In October 2010, the Seventh Circuit dismissed all remaining claims in these cases. 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 December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. 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, 2010, CSPCo is named as a Potentially Responsible Party (PRP) for one site by the Federal EPA. There are two 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 retrofits on the Conesville Plant unit are operational. Due to unexpected operating results, management completed an extensive review in 2009 of the design and manufacture of the JBR internal components. The review concluded that there were 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. In 2010, management settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

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.

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 one unfunded nonqualified pension plan. Substantially all employees are covered by the qualified plan or both the qualified and nonqualified pension plans. CSPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		**Other Postretirement Benefit Plans**	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase (a)	5.30 %	4.95 %	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.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed 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 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with the average increase of 5.30%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		**Other Postretirement Benefit Plans**	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.60 %	6.00 %	5.85 %	6.10 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	7.75 %
Rate of Compensation Increase	4.95 %	6.25 %	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 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	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	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 thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 1,471	$ (1,186)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	17,761	(14,571)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See “Investments Held in Trust for Future Liabilities” section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

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

	Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 361,472	$ 341,550	$ 139,593	$ 140,283
Service Cost	5,818	5,435	2,558	2,278
Interest Cost	18,935	19,345	8,047	7,851
Actuarial (Gain) Loss	7,046	15,606	11,356	(3,822)
Plan Amendment Prior Service Credit	-	-	(2,149)	-
Benefit Payments	(43,426)	(20,464)	(11,748)	(9,831)
Participant Contributions	-	-	2,458	2,124
Medicare Subsidy	-	-	713	710
Benefit Obligation at December 31	$ 349,845	$ 361,472	$ 150,828	$ 139,593
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 286,073	$ 269,146	$ 97,645	$ 80,475
Actual Gain on Plan Assets	28,262	37,391	11,978	14,593
Company Contributions	6,404	-	7,907	10,284
Participant Contributions	-	-	2,458	2,124
Benefit Payments	(43,426)	(20,464)	(11,748)	(9,831)
Fair Value of Plan Assets at December 31	$ 277,313	$ 286,073	$ 108,240	$ 97,645
Underfunded Status at December 31	$ (72,532)	$ (75,399)	$ (42,588)	$ (41,948)

Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
	(in thousands)			
Accumulated Provision for Pensions and Benefits - Long-term Benefit Liability	$ (72,532)	$ (75,399)	$ (42,588)	$ (41,948)
Underfunded Status	$ (72,532)	$ (75,399)	$ (42,588)	$ (41,948)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in thousands)			
Net Actuarial Loss	$ 199,183	$ 200,937	$ 43,462	$ 38,277
Prior Service Cost (Credit)	1,283	1,843	(886)	-
Transition Obligation	-	-	-	3,648
Recorded as				
Regulatory Assets	$ 144,607	$ 146,082	$ 29,148	$ 28,942
Deferred Income Taxes	19,551	19,844	4,700	4,544
Net of Tax AOCI	36,308	36,854	8,728	8,439

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
Components	2010	2009	2010	2009
	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 4,877	$ 5,260	$ 7,199	$ (12,447)
Prior Service Credit	-	-	(2,149)	-
Amortization of Actuarial Gain (Loss)	(6,630)	(4,389)	(2,014)	(3,029)
Amortization of Prior Service Costs	(561)	(561)	-	-
Amortization of Transition Obligation	-	-	(2,385)	(2,385)
Change for the Year	$ (2,314)	$ 310	$ 651	$ (17,861)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 97,021	$ 198	$ -	$ -	$ 97,219	35.1 %
International	28,962	-	-	-	28,962	10.4 %
Real Estate Investment Trusts	8,075	-	-	-	8,075	2.9 %
Common Collective Trust - International	-	11,690	-	-	11,690	4.2 %
Subtotal - Equities	134,058	11,888	-	-	145,946	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	45,574	-	-	45,574	16.4 %
Corporate Debt	-	48,286	-	-	48,286	17.4 %
Foreign Debt	-	9,139	-	-	9,139	3.3 %
State and Local Government	-	1,634	-	-	1,634	0.6 %
Other - Asset Backed	-	3,676	-	-	3,676	1.3 %
Subtotal - Fixed Income	-	108,309	-	-	108,309	39.0 %
Real Estate	-	-	5,981	-	5,981	2.2 %
Alternative Investments	-	-	9,344	-	9,344	3.4 %
Securities Lending	-	18,279	-	-	18,279	6.6 %
Securities Lending Collateral (a)	-	-	-	(19,826)	(19,826)	(7.1)%
Cash and Cash Equivalents (b)	-	9,122	-	114	9,236	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	44	44	- %
Total	$ 134,058	$ 147,598	$ 15,325	$ (19,668)	$ 277,313	100.0 %

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

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 7,608	$ 8,883	$ 16,491
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,627)	75	(1,552)
Relating to Assets Sold During the Period	-	24	24
Purchases and Sales	-	362	362
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 5,981	$ 9,344	$ 15,325

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year end Allocation
			(in thousands)			
Equities:						
Domestic	$ 43,279	$ -	$ -	$ -	$ 43,279	40.0 %
International	16,337	-	-	-	16,337	15.1 %
Common Collective Trust - Global	-	8,504	-	-	8,504	7.9 %
Subtotal - Equities	59,616	8,504	-	-	68,120	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,537	-	-	3,537	3.3 %
United States Government and Agency Securities	-	6,943	-	-	6,943	6.4 %
Corporate Debt	-	8,155	-	-	8,155	7.5 %
Foreign Debt	-	1,838	-	-	1,838	1.7 %
State and Local Government	-	259	-	-	259	0.2 %
Other - Asset Backed	-	70	-	-	70	0.1 %
Subtotal - Fixed Income	-	20,802	-	-	20,802	19.2 %
Trust Owned Life Insurance:						
International Equities	-	3,636	-	-	3,636	3.3 %
United States Bonds	-	12,046	-	-	12,046	11.1 %
Cash and Cash Equivalents (a)	1,519	1,855	-	64	3,438	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	198	198	0.2 %
Total	$ 61,135	$ 46,843	$ -	$ 262	$ 108,240	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 following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 102,520	$ -	$ -	$ -	$ 102,520	35.8 %
International	26,892	-	-	-	26,892	9.4 %
Real Estate Investment Trusts	7,286	-	-	-	7,286	2.6 %
Common Collective Trust - International	-	13,541	-	-	13,541	4.7 %
Subtotal - Equities	136,698	13,541	-	-	150,239	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	19,571	-	-	19,571	6.9 %
Corporate Debt	-	69,840	-	-	69,840	24.4 %
Foreign Debt	-	14,367	-	-	14,367	5.0 %
State and Local Government	-	2,893	-	-	2,893	1.0 %
Other - Asset Backed	-	2,304	-	-	2,304	0.8 %
Subtotal - Fixed Income	-	108,975	-	-	108,975	38.1 %
Real Estate	-	-	7,608	-	7,608	2.7 %
Alternative Investments	-	-	8,883	-	8,883	3.1 %
Securities Lending	-	14,572	-	-	14,572	5.1 %
Securities Lending Collateral (a)	-	-	-	(16,461)	(16,461)	(5.8)%
Cash and Cash Equivalents (b)	-	9,719	-	339	10,058	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	2,199	2,199	0.8 %
Total	$ 136,698	$ 146,807	$ 16,491	$ (13,923)	$ 286,073	100.0 %

(a) Amounts in “Other” column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in “Other” column primarily represent 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 pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2009	$ 11,546	$ 8,951	$ 20,497
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(3,938)	(1,165)	(5,103)
Relating to Assets Sold During the Period	-	35	35
Purchases and Sales	-	1,062	1,062
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 7,608	$ 8,883	$ 16,491

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 25,652	$ -	$ -	$ -	$ 25,652	26.2 %
International	27,986	-	-	-	27,986	28.7 %
Common Collective Trust - Global	-	6,955	-	-	6,955	7.1 %
Subtotal - Equities	53,638	6,955	-	-	60,593	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	2,834	-	-	2,834	2.9 %
United States Government and Agency Securities	-	3,127	-	-	3,127	3.2 %
Corporate Debt	-	10,566	-	-	10,566	10.8 %
Foreign Debt	-	2,398	-	-	2,398	2.4 %
State and Local Government	-	448	-	-	448	0.5 %
Other - Asset Backed	-	105	-	-	105	0.2 %
Subtotal - Fixed Income	-	19,478	-	-	19,478	20.0 %
Trust Owned Life Insurance:						
International Equities	-	5,562	-	-	5,562	5.7 %
United States Bonds	-	9,784	-	-	9,784	10.0 %
Cash and Cash Equivalents (a)	491	1,074	-	74	1,639	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	589	589	0.6 %
Total	$ 54,129	$ 42,853	$ -	$ 663	$ 97,645	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.

Determination of Pension Expense

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

	December31,	
Accumulated Benefit Obligation	**2010**	**2009**
	(in thousands)	
Qualified Pension Plan	$ 345,848	$ 358,661
Nonqualified Pension Plans	6	-
Total	$ 345,854	$ 358,661

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, 2010 and 2009 were as follows:

	December 31,	
	2010	**2009**
	(in thousands)	
Projected Benefit Obligation	$ 349,845	$ 361,472
Accumulated Benefit Obligation	$ 345,854	$ 358,661
Fair Value of Plan Assets	277,313	286,073
Underfunded Accumulated Benefit Obligation	$ (68,541)	$ (72,588)

Estimated Future Benefit Payments and Contributions

CSPCo expects contributions and payments for the pension plans of $4.7 million and the OPEB plans of $5.1 million during 2011. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by ERISA plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may be made to the trust to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided 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 CSPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. 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 the pension benefits and OPEB are as follows:

		Other Postretirement Benefit Plans	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in thousands)	
2011	$ 26,987	$ 11,756	$ (812)
2012	27,033	12,170	(916)
2013	26,880	12,538	(1,022)
2014	27,283	12,928	(1,125)
2015	27,201	13,113	(1,239)
Years 2016 to 2020, in Total	134,946	68,402	(7,675)

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2010 and 2009:

	Pension Plans		**Other Postretirement Benefit Plans**	
	Years Ended December 31,			
	2010	**2009**	**2010**	**2009**
	(in thousands)			
Service Cost	$ 5,818	$ 5,435	$ 2,558	$ 2,278
Interest Cost	18,935	19,345	8,047	7,851
Expected Return on Plan Assets	(26,117)	(27,045)	(7,822)	(6,058)
Amortization of Transition Obligation	-	-	2,385	2,385
Amortization of Prior Service Cost	561	561	-	-
Amortization of Net Actuarial Loss	6,630	4,389	2,014	3,029
Net Periodic Benefit Cost	5,827	2,685	7,182	9,485
Capitalized Portion	(1,888)	(897)	(2,327)	(3,168)
Net Periodic Benefit Cost Recognized as Expense	$ 3,939	$ 1,788	$ 4,855	$ 6,317

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 is shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 8,765	$ 2,278
Prior Service Cost (Credit)	561	(73)
Total Estimated 2011 Amortization	$ 9,326	$ 2,205
Expected to be Recorded as		
Regulatory Asset	$ 6,470	$ 1,523
Deferred Income Taxes	1,000	239
Net of Tax AOCI	1,856	443
Total	$ 9,326	$ 2,205

American Electric Power System Retirement Savings Plans

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 are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the retirement savings plans for the years ended December 31, 2010 and 2009 was $3.2 million and $4 million, 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. CSPCo administers the health and welfare benefits and pays them from its general assets. Contributions and benefits paid were not material in 2010 and 2009.

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. AEPSC, on behalf of CSPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of CSPCo.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of 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 power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of CSPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of 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, 2010 and 2009:

Notional Volume of Derivative Instruments
December 31, 2010 and 2009

Primary Risk Exposure	Volumes 2010	Volumes 2009	Unit of Measure
	(in thousands)		
Commodity:			
Power	111,959	96,828	MWHs
Coal	5,550	5,615	Tons
Natural Gas	1,248	9,051	MMBtus
Heating Oil and Gasoline	467	474	Gallons
Interest Rate	$ 5,471	$ 10,658	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

AEPSC, on behalf of CSPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. 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 heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” CSPCo does not hedge all fuel price risk.

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

At times, CSPCo is exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP’s risk management policy, AEPSC, on behalf of CSPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. CSPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, management 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, 2010 and 2009 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,			
2010		2009	
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)			
$ 1,042	$ 9,347	$ 1,920	$ 16,108

The following tables represent the gross fair value of derivative activity on the balance sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

	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	$ 195,299	$ -	$ -	$ (149,665)	$ 45,634
Long-Term Portion of Derivative Instrument Assets	45,413	-	-	(23,332)	22,081
Derivative Instrument Assets – Hedges	-	1,576	-	(1,347)	229
Long-Term Portion of Derivative Instrument Assets – Hedges	-	412	-	(404)	8
Derivative Instrument Liabilities	181,684	-	-	(159,913)	21,771
Long-Term Portion of Derivative Instrument Liabilities	35,144	-	-	(28,921)	6,223
Derivative Instrument Liabilities – Hedges	-	1,766	-	(1,347)	419
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	404	-	(404)	-

Fair Value of Derivative Instruments
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 years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Years Ended December 31, 2010 and 2009

Location of Gain (Loss)	**2010**	**2009**
	(in thousands)	
Operating Revenues	$ 19,799	$ 23,088
Regulatory Assets (a)	(2,591)	(10,281)
Regulatory Liabilities (a)	1,498	(3,486)
Total Gain (Loss) on Risk Management Contracts	$ 18,706	$ 9,321

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances.

Accounting for Fair Value Hedging Strategies

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

CSPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Charges on the statements of income. For the years ended December 31, 2010 and 2009, CSPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows 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 power, coal, natural gas and heating oil and gasoline 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 2010 and 2009, CSPCo designated commodity derivatives as cash flow hedges.

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 2010 and 2009, CSPCo designated heating oil and gasoline derivatives as cash flow hedges.

CSPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income into Interest Charges in those periods in which hedged interest payments occur.

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

During 2010 and 2009, hedge ineffectiveness was immaterial for all of the hedge strategies disclosed above.

The following tables provide 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 years ended December 31, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity Contracts	Interest Rate And Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (376)	$ -	$ (376)
Changes in Fair Value Recognized in AOCI	(852)	-	(852)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/ within Balance Sheet			
Operating Revenues	112	-	112
Operation Expenses	1,035	-	1,035
Maintenance Expenses	(21)	-	(21)
Depreciation Expense	-	-	-
Interest on Long-Term Debt	-	-	-
Utility Plant	(32)	-	(32)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ (134)	$ -	$ (134)

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

	Commodity Contracts	Interest Rate And Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2008	$ 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)	-	-	-
Balance in AOCI as of December 31, 2009	$ (376)	$ -	$ (376)

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

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets at December 31, 2010 and 2009 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 229	$ -	$ 229
Hedging Liabilities (a)	(419)	-	(419)
AOCI Loss Net of Tax	(134)	-	(134)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(137)	-	(137)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 984	$ -	$ 984
Hedging Liabilities (a)	(1,794)	-	(1,794)
AOCI Loss Net of Tax	(376)	-	(376)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(349)	-	(349)

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

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes. As of December 31, 2010, the maximum length of time that CSPCo is hedging (with contracts subject to the accounting guidance for “Derivatives and Hedging”) exposure to variability in future cash flows related to forecasted transactions is 41 months.

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, Standard and Poor’s and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of 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 the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, CSPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) CSPCo's aggregate fair values of such derivative contracts, (b) the amount of collateral CSPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral CSPCo Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
December 31, 2010	$ 3,801	$ 7,267	$ 7,248
December 31, 2009	1,129	4,272	4,026

As of December 31, 2010 and 2009, CSPCo was not required to post any collateral.

In addition, a majority of CSPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding 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 does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by CSPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering CSPCo's contractual netting arrangements as of December 31, 2010 and 2009:

	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
December 31, 2010	$ 44,277	$ 3,826	$ 13,689
December 31, 2009	78,489	1,578	16,813

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 as of December 31, 2010 and 2009 are summarized in the following table:

December 31,			
2010		2009	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 1,438,830	$ 1,571,219	$ 1,536,393	$ 1,616,857

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, the financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (e)	$ 972	$ 185,699	$ 7,950	$ (150,930)	$ 43,691
Dedesignated Risk Management Contracts (b)	-	-	-	1,943	1,943
Total Derivative Instrument Assets	972	185,699	7,950	(148,987)	45,634
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	1,531	-	(1,302)	229
Total Assets	$ 972	$ 187,230	$ 7,950	$ (150,289)	$ 45,863
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (e)	$ 953	$ 175,078	$ 4,975	$ (159,235)	$ 21,771
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (a)	-	1,721	-	(1,302)	419
Total Liabilities	$ 953	$ 176,799	$ 4,975	$ (160,537)	$ 22,190

Assets and Liabilities Measured at Fair Value on a Recurring Basis
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 Commodity 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					
Cash Flow Hedges – Commodity (a)	-	1,805	-	(821)	984
Total Assets	$ 17,317	$ 228,955	$ 6,518	$ (178,415)	$ 74,375
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity 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					
Cash Flow Hedges – Commodity (a)	-	2,615	-	(821)	1,794
Total Liabilities	$ 1,342	$ 215,945	$ 1,742	$ (195,664)	$ 23,365

(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) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for “Derivatives and Hedging.” At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

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

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

(e) Substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the year ended December 31, 2010.

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

Year Ended December 31, 2010	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2009	$ 4,776
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	946
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9,601
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(4,039)
Transfers into Level 3 (d) (h)	614
Transfers out of Level 3 (e) (h)	(6,332)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(2,591)
Balance as of December 31, 2010	$ 2,975

Year Ended December 31, 2009	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2008	$ 4,497
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(743)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4,234
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(2,940)
Transfers in and/or out of Level 3 (f)	(272)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	-
Balance as of December 31, 2009	$ 4,776

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

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2010	2009
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 61,985	$ 19,894
Deferred	79,826	140,728
Deferred Investment Tax Credits	(2,046)	(1,980)
Total	139,765	158,642
Charged (Credited) to Nonoperating Income, Net:		
Current	(4,123)	(5,946)
Deferred	(4,002)	(8,997)
Total	(8,125)	(14,943)
Total Income Taxes	$ 131,640	$ 143,699

Shown below is a reconciliation of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31, 2010	2009
	(in thousands)	
Net Income	$ 230,223	$ 271,661
Income Taxes	131,640	143,699
Pretax Income	$ 361,863	$ 415,360
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 126,652	$ 145,376
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	5,641	3,776
Investment Tax Credits, Net	(2,046)	(1,980)
State and Local Income Taxes	2,747	2,894
Parent Company Loss Benefit	(7,129)	(2,973)
Other	5,775	(3,394)
Total Income Taxes	$ 131,640	$ 143,699
Effective Income Tax Rate	36.4%	34.6 %

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

	December 31,	
	2010	**2009**
	(in thousands)	
Deferred Tax Assets	$ 136,598	$ 118,960
Deferred Tax Liabilities	(771,078)	(684,880)
Net Deferred Tax Liabilities	$ (634,480)	$ (565,920)
Property-Related Temporary Differences	$ (587,170)	$ (496,890)
Amounts Due from Customers for Future Federal Income Taxes	(1,013)	(3,182)
Deferred State Income Taxes	(7,495)	(9,223)
Deferred Income Taxes on Other Comprehensive Loss	24,322	24,590
Accrued Pensions	7,121	8,167
Regulatory Assets	(78,623)	(74,298)
All Other, Net	8,378	(15,084)
Net Deferred Tax Liabilities	$ (634,480)	$ (565,920)

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 adequate provisions for income taxes have been made for potential liabilities resulting from such challenges, and 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, 2010	Years Ended December 31, 2009
	(in thousands)	
Interest Expense	$ 1,549	$ 1,091
Interest Income	-	-
Reversal of Prior Period Interest Expense	39	200

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

	December 31, 2010	December 31, 2009
	(in thousands)	
Accrual for Receipt of Interest	$ 2,784	$ 2,281
Accrual for Payment of Interest and Penalties	2,219	206

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

	2010	2009
	(in thousands)	
Balance at January 1,	$ 16,738	$ 21,179
Increase - Tax Positions Taken During a Prior Period	10,110	6,068
Decrease - Tax Positions Taken During a Prior Period	(1,496)	(9,994)
Increase - Tax Positions Taken During the Current Year	(597)	-
Decrease - Tax Positions Taken During the Current Year	-	(195)
Increase - Settlements with Taxing Authorities	-	-
Decrease - Settlements with Taxing Authorities	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	(320)
Balance at December 31,	$ 24,755	$ 16,738

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $10.7 million and $9.7 million for 2010 and 2009, respectively. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date.

Federal Tax Legislation

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision.

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 that resulted in a 2010 cash flow benefit to CSPCo of $3.2 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by CSPCo in March 2010. This reduction, which was partially offset by recording net tax regulatory assets, did not materially affect CSPCo's cash flows or financial condition, but decreased net income by approximately $1.3 million for the year ended December 31, 2010.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on CSPCo's net income or financial condition but had a favorable impact on cash flows in 2010 of approximately $85 million.

State Tax Legislation

Ohio House Bill 66 imposed a commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $6 million and $5 million were recorded in 2010 and 2009, respectively.

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, 2010	2009
	(in thousands)	
Net Lease Expense on Operating Leases	$ 39,997	$ 45,114
Amortization of Capital Leases	4,067	2,572
Interest on Capital Leases	635	135
Total Lease Rental Costs	$ 44,699	$ 47,821

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

	December 31, 2010	December 31, 2009
	(in thousands)	
Property, Plant and Equipment Under Capital Leases:		
Production	$ 1,696	$ 6,989
Other Property, Plant and Equipment	13,916	7,754
Total Property, Plant and Equipment	15,612	14,743
Accumulated Amortization	(3,952)	10,409
Net Property, Plant and Equipment Under Capital Leases	$ 11,660	$ 4,334
Obligations Under Capital Leases:		
Noncurrent	$ 7,964	$ 2,239
Current	3,764	2,124
Total Obligations Under Capital Leases	$ 11,728	$ 4,363

Future minimum lease payments consisted of the following at December 31, 2010:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2011	$ 4,239	$ 38,892
2012	2,769	36,480
2013	2,379	34,911
2014	1,820	33,456
2015	695	31,920
Later Years	1,284	60,936
Total Future Minimum Lease Payments	13,186	$ 236,595
Less Estimated Interest Element	1,458	
Estimated Present Value of Future Minimum Lease Payments	$ 11,728	

Master Lease Agreements

CSPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing, but the assets will be purchased or refinanced in 2011. In addition, certain operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. The amounts refinanced for CSPCo are as follows:

Leases Refinanced with GE		**(in thousands)**
Operating Lease to Operating Lease	$	8,363
Capital Lease to Capital Lease		739
Operating Lease to Capital Lease		1,906

These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair 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 value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other 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 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, 2010, the maximum potential loss for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is $888 thousand ($577 thousand, net of tax). Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Preferred Stock

As of December 31, 2010, 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, 2010 and 2009, there were no outstanding shares.

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2010 and 2009:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	Interest Rate Ranges at December 31, 2009	Outstanding at December 31, 2010	Outstanding at December 31, 2009
					(in thousands)	
Senior Unsecured Notes	2010-2035	5.37%	0.702%-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%	3.875%-5.80%	192,745	192,745
Notes Payable - Affiliated	2010	-	-	4.64%	-	100,000
Unamortized Discount					(3,915)	(6,352)
Total Long-term Debt					$ 1,438,830	$ 1,536,393

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
(b) Certain pollution control bonds are subject to 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, 2010 is payable as follows:

	(in thousands)
2011	$ -
2012	194,500
2013	306,000
2014	60,000
2015	-
After 2015	882,245
Total Principal Amount	1,442,745
Unamortized Discount	(3,915)
Total Long-term Debt Outstanding	$ 1,438,830

Dividend Restrictions

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

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

Charter and Leverage Restrictions

Provisions within the articles or certificates of incorporation of CSPCo relating to preferred stock or shares restrict the payment of cash dividends on common and preferred stock or shares. Pursuant to the credit agreement leverage restrictions, CSPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

At December 31, 2010, approximately $77 million of the retained earnings of CSPCo have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of December 31, 2010 is included in Notes Receivable from Associated Companies in the balance sheets. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2009 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, 2010 and 2009 are described in the following table:

Years Ended December 31,	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans/(Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
			(in thousands)			
2010	$ 139,297	$ 225,315	$ 31,117	$ 95,737	$ 49,741	$ 350,000
2009	212,608	3,113	108,907	3,113	(28,793)	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, 2010 and 2009 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
2010	0.51%	0.09%	0.55%	0.11%	0.18%	0.26%
2009	2.28%	0.15%	0.58%	0.58%	1.04%	0.58%

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 $12 thousand and $1.2 million for the years ended December 31, 2010 and 2009, 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 $197 thousand and $329 thousand for the years ended December 31, 2010 and 2009, respectively.

Sale of Receivables – AEP Credit

Under a sale of receivables 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's financing costs and administrative costs and CSPCo's uncollectible accounts experience. CSPCo manages and services its customer accounts receivable sold.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement was $176 million and $169.1 million at December 31, 2010 and 2009, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $11.4 million and $11.2 million for the years ended December 31, 2010 and 2009, respectively.

CSPCo's proceeds on the sale of receivables to AEP Credit were $1.8 billion and $1.6 billion for the years ended December 31, 2010 and 2009, respectively.

12. <u>RELATED PARTY TRANSACTIONS</u>

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 December 2010, each AEP Power Pool member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by the FERC. It is unknown at this time what will replace the Interconnection Agreement. In addition, since 1995, CSPCo, along with APCo, I&M, KPCo and OPCo, has been party 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. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

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

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates approved (other than in Ohio) by the public utility commission in the jurisdiction of sale. In Ohio, such rates are based on a statutory formula as that jurisdiction 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, 2010 and 2009:

	Years Ended December 31,	
Related Party Revenues	**2010**	**2009**
	(in thousands)	
Sales to AEP Power Pool	$ 64,467	$ 57,373
Direct Sales to West Affiliates	1,900	1,169
Direct Sales to Transmission Companies	113	-
Natural Gas Contracts with AEPES	(1,072)	(4,866)
Other Revenues	17,586	13,537

The following table shows the purchased power expense incurred for purchases from the pools and affiliates for the years ended December 31, 2010 and 2009:

Related Party Purchases	Years ended December 31, 2010	Years ended December 31, 2009
	(in thousands)	
Purchases from AEP Power Pool	$ 294,838	$ 316,490
Direct Purchases from West Affiliates	458	802
Purchases from AEGCo	113,801	75,469

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. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

CSPCo's net charges allocated under the TA during the years ended December 31, 2010 and 2009 were $42.5 million and $51.3 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 a 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. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, 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. The agreement between AEPSC and AEPES ended December 31, 2010, coinciding with the settlement of the remaining DETM contracts. CSPCo's risk management liability related to DETM at December 31, 2009 was $1.4 million.

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 $535 thousand and $229 thousand for the years ended December 31, 2010 and 2009, 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 balance sheet the cost of performing the services, then transfers the cost to its 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 $397 thousand and $1.3 million by APCo for the years ended December 31, 2010 and 2009, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to CSPCo through 2010. The realized and unrealized amounts recorded for the years ended December 31, 2010 and 2009 were $1.6 million and $783 thousand, respectively.

Affiliate Railcar Agreement

CSPCo has an agreement providing for the use of its 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 recorded these costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on the balance sheets and such costs are recoverable from customers. Under the agreement, CSPCo paid its affiliates $9 thousand and $11 thousand for the years ended December 31, 2010 and 2009, respectively.

Purchased Power from OVEC

CSPCo paid $29.8 million and $29.3 million for power purchased from OVEC for the years ended December 31, 2010 and 2009, respectively. The purchases are recoverable from customers and included in Operation Expenses.

AEP Power Pool Purchases from OVEC

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. CSPCo's purchases serving off-system sales of $3.7 million are reported net as a reduction in Operating Revenues. CSPCo's purchases serving retail sales of $2 million are reported in Operation Expenses.

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, 2010 and 2009 as shown in the following table:

Companies	Years Ended December 31, 2010	2009
	(in thousands)	
CSPCo to I&M	$ 1,459	$ -
CSPCo to KPCo	433	-
OPCo to CSPCo	686	344

In addition, CSPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2010 and 2009 as shown in the following tables:

Sales	APCo	I&M	OPCo	PSO	SWEPCo	TCC	WPCo	Total
				(in thousands)				
2010	$ 65	$ 3	$ 1,164	$ 74	$ 908	$ 157	$ 6	$ 2,377
2009	30	26	664	93	6	-	3	$ 822

Purchases	APCo	I&M	KPCo	OPCo	PSO	SWEPCo	WPCo	Total
				(in thousands)				
2010	$ 17	$ 46	$ 9	$ 6,085	$ 42	$ 2	$ 1	$ 6,202
2009	32	88	23	2,748	42	27	6	2,966

The amounts above are recorded in Utility Plant at cost.

Global Borrowing Notes

AEP has intercompany notes in place with CSPCo. The debt is reflected in Advances from Associated Companies on CSPCo's balance sheets. CSPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Interest Accrued on CSPCo's balance sheets.

Intercompany Billings

CSPCo and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings between affiliated subsidiaries 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 subsidiaries 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 through cost reimbursement from AEP subsidiaries. There are no other terms or arrangements between AEPSC and any other AEP subsidiary that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC's billings are subject to regulation by the FERC. 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 $136 million and $124 million for the years ended December 31, 2010 and 2009, 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 Production	Steam	Transmission	Distribution	General
			(in percentages)		
2010	2.3	2.1	2.3	3.5	8.6
2009	2.3	1.9	2.2	3.4	10.2

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. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

CSPCo record 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 2010 and 2009 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)			
2010	$ 39,349	$ 2,794	$ 1,452	$ (1,709)	$ 8,442	$ 50,328
2009	16,321	1,387	-	(2,853)	24,494	39,349

Jointly-owned Electric Facilities

CSPCo has electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company 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 income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

			Company's Share at December 31, 2010		
Company	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19,079	$ 248	$ 8,003
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	300,618	8,259	49,121
J.M. Stuart Generating Station (c)	Coal	26.0 %	506,756	22,435	162,869
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771,236	9,636	365,989
Transmission	N/A	(d)	62,952	3,008	47,957
Total			$ 1,660,641	$ 43,586	$ 633,939

Company	Fuel Type	Percent of Ownership	Company's Share at December 31, 2009: Utility Plant in Service	Construction Work in Progress	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

(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.
N/A Not Applicable

14. COST REDUCTION INITIATIVES

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

Management recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries	Settled	Adjustments	Remaining Balance at December 31, 2010
		(in thousands)		
$ 11,040	$ 20,788	$ 30,520	$ 117	$ 1,425

These costs relate primarily to severance benefits.

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 2010/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				(48,382,289)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,337,017)
3	Preceding Quarter/Year to Date Changes in Fair Value				1,101,031
4	Total (lines 2 and 3)				(1,235,986)
5	Balance of Account 219 at End of Preceding Quarter/Year				(49,618,275)
6	Balance of Account 219 at Beginning of Current Year				(49,618,275)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,475,300
8	Current Quarter/Year to Date Changes in Fair Value				(4,059,890)
9	Total (lines 7 and 8)				(1,584,590)
10	Balance of Account 219 at End of Current Quarter/Year				(51,202,865)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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		1,531,429	(46,850,860)		
2		(1,444,432)	(3,781,449)		
3		(462,253)	638,778		
4		(1,906,685)	(3,142,671)	271,661,103	268,518,432
5		(375,256)	(49,993,531)		
6		(375,256)	(49,993,531)		
7		1,094,226	3,569,526		
8		(852,000)	(4,911,890)		
9		242,226	(1,342,364)	230,222,375	228,880,011
10		(133,030)	(51,335,895)		

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 2010/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)	5,130,804,086	5,130,804,086
4	Property Under Capital Leases	11,660,237	11,660,237
5	Plant Purchased or Sold		
6	Completed Construction not Classified	249,798,045	249,798,045
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,392,262,368	5,392,262,368
9	Leased to Others		
10	Held for Future Use	13,026,227	13,026,227
11	Construction Work in Progress	172,753,317	172,753,317
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,578,041,912	5,578,041,912
14	Accum Prov for Depr, Amort, & Depl	2,146,718,452	2,146,718,452
15	Net Utility Plant (13 less 14)	3,431,323,460	3,431,323,460
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,093,433,281	2,093,433,281
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	52,419,579	52,419,579
22	Total In Service (18 thru 21)	2,145,852,860	2,145,852,860
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	865,592	865,592
29	Amortization		
30	Total Held for Future Use (28 & 29)	865,592	865,592
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,146,718,452	2,146,718,452

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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					33

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 2010/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
			3
			4
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			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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	55,515,834	8,751,284
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	55,521,109	8,751,284
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	7,206,136	
9	(311) Structures and Improvements	254,533,572	3,037,694
10	(312) Boiler Plant Equipment	1,530,423,913	40,850,118
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	307,825,479	1,755,489
13	(315) Accessory Electric Equipment	147,121,013	1,736,179
14	(316) Misc. Power Plant Equipment	40,644,270	1,809,446
15	(317) Asset Retirement Costs for Steam Production	32,807,106	9,893,926
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,320,561,489	59,082,852
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	13,904,595	-259
39	(342) Fuel Holders, Products, and Accessories	7,528,296	124,732
40	(343) Prime Movers		
41	(344) Generators	323,387,469	988,213
42	(345) Accessory Electric Equipment	45,863,085	71,992
43	(346) Misc. Power Plant Equipment	8,088,339	391,917
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	402,485,368	1,576,595
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,723,046,857	60,659,447

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	38,046,102	1,826,355
49	(352) Structures and Improvements	48,363,214	49,605
50	(353) Station Equipment	309,136,250	28,461,781
51	(354) Towers and Fixtures	35,050,127	
52	(355) Poles and Fixtures	81,533,801	8,024,956
53	(356) Overhead Conductors and Devices	78,193,780	2,890,568
54	(357) Underground Conduit	10,497,884	
55	(358) Underground Conductors and Devices	19,062,691	141,493
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)	619,883,849	41,394,758
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	28,313,252	415,485
61	(361) Structures and Improvements	9,781,492	
62	(362) Station Equipment	221,705,860	19,053,976
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	226,773,173	8,524,164
65	(365) Overhead Conductors and Devices	230,548,474	17,962,284
66	(366) Underground Conduit	88,288,644	7,995,527
67	(367) Underground Conductors and Devices	362,865,773	15,814,017
68	(368) Line Transformers	300,368,843	10,339,966
69	(369) Services	134,106,771	4,969,630
70	(370) Meters	102,724,833	-9,514,934
71	(371) Installations on Customer Premises	24,672,218	1,290,887
72	(372) Leased Property on Customer Premises	102,689	
73	(373) Street Lighting and Signal Systems	12,354,702	296,714
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,742,606,724	77,147,716
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	3,117,122	-347,282
87	(390) Structures and Improvements	58,974,649	798,229
88	(391) Office Furniture and Equipment	5,067,274	246,902
89	(392) Transportation Equipment	40,258	4,721
90	(393) Stores Equipment	301,966	
91	(394) Tools, Shop and Garage Equipment	10,353,142	255,102
92	(395) Laboratory Equipment	631,927	
93	(396) Power Operated Equipment	3,036	
94	(397) Communication Equipment	15,606,820	2,276,240
95	(398) Miscellaneous Equipment	1,621,537	44,438
96	SUBTOTAL (Enter Total of lines 86 thru 95)	95,717,731	3,278,350
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)	95,862,102	3,278,350
100	TOTAL (Accounts 101 and 106)	5,236,920,641	191,231,555
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)	5,236,920,641	191,231,555

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
4,028,537			60,238,581		4
4,028,537			60,243,856		5
					6
					7
			7,206,136		8
189,091			257,382,175		9
8,467,251			1,562,806,780		10
					11
1,041,867			308,539,101		12
407,645			148,449,547		13
215,912		5,951	42,243,755		14
			42,701,032		15
10,321,766		5,951	2,369,328,526		16
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					36
			3,713,584		37
			13,904,336		38
107,907			7,545,121		39
					40
470,136			323,905,546		41
939			45,934,138		42
49,641		12,583	8,443,198		43
					44
628,623		12,583	403,445,923		45
10,950,389		18,534	2,772,774,449		46

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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
		913,727	40,786,184		48
914			48,411,905		49
2,594,647			335,003,384		50
			35,050,127		51
695,159			88,863,598		52
65,038			81,019,310		53
2			10,497,882		54
320,817			18,883,367		55
					56
					57
3,676,577		913,727	658,515,757		58
					59
22		-1,766,274	26,962,441		60
			9,781,492		61
1,353,938		177,259	239,583,157		62
					63
1,980,082			233,317,255		64
3,019,126			245,491,632		65
41,013		-126,116	96,117,042		66
1,341,558		-51,142	377,287,090		67
4,565,124			306,143,685		68
1,002,408			138,073,993		69
11,050,089			82,159,810		70
680,034			25,283,071		71
			102,689		72
287,945			12,363,471		73
					74
25,321,339		-1,766,273	1,792,666,828		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		478,120	3,247,960		86
-2,525		51,960	59,827,363		87
27,983		-12,583	5,273,610		88
5,568			39,411		89
			301,966		90
			10,608,244		91
			631,927		92
			3,036		93
3,167,771			14,715,289		94
		-57,911	1,608,064		95
3,198,797		459,586	96,256,870		96
					97
			144,371		98
3,198,797		459,586	96,401,241		99
47,175,639		-374,426	5,380,602,131		100
					101
					102
					103
47,175,639		-374,426	5,380,602,131		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 2010/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					
5					
6					
7					
8					
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12					
13					
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42					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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			1,847,211
20				
21	Other Property:			
22				
23				
24				
25	Items under $250,000			874,775
26				
27				
28				
29				
30				
31				
32				
33				
34				
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38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			13,026,227

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 2010/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	Shanahan Substation (0277)	11/1/2010	2015	264,761
6				
7				
8				
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15				
16				
17				
18				
19				
20				
21	Other Property:			
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44				
45				
46				
47	Total			13,026,227

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 2010/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	CV4 FGD Landfill	13,095,576
2	TL/CSP/Rome - Hilliard Line Re	2,324,960
3	TLCSPROSS-HIGHLAND REBLD	6,804,088
4	TL/CSP/New Roberts - OSU 138 k	1,074,835
5	TS/CSP/new Roberts Station Cst	9,181,466
6	TSCSPLincoln - Berrywood	2,697,467
7	DS/CSP/Purchase-Rebuild Eq	1,654,491
8	DCSPBrkr Task Force Upgrade	1,363,782
9	T/CSP/Security Application Enh	9,282,013
10	TSCSPCCD Replace Zimmer 345k	2,821,564
11	CV CI U4 HP TURBINE UPGRADE	2,386,341
12	CV56 Mercury Minimization STP	17,348,505
13	CV456 Mecury Minimization FAU	4,475,165
14	CSP-Cols North Ntwk Rebuild	2,277,516
15	CSP Mifflin Station	1,241,843
16	CSP/Mifflin Station T FERC	1,099,379
17	CSP/Hemlock Station D FERC	1,965,653
18	Battelle Assistance and Other	1,935,835
19	Oh gSmart Ph1 STA	1,882,620
20	CUST OPS gridSMART-CSP-D	2,954,060
21	U1 Replace Pendant Reheater	2,525,892
22	Stuart FGD Improvements	2,505,321
23	Stuart U1 Low NOx Burner Proj	2,835,845
24	T/CSP/Trans Line ReRehab/Repla	1,179,029
25	TL/CSP/Wilson-Briggsdale 40kV	1,246,902
26	WS-CI-CSPCo-G PPB	4,196,290
27	WS-CI-CCDCo-G PPB	10,632,302
28	ET-CI-CSPCo-T ASSET IMP	1,866,037
29	Ed-Ci-Cspco-D Ast Imp	5,349,000
30	Ed-Ci-Cspco-D Cust Mtr	2,617,545
31	Ed-Ci-Cspco-D Cust Serv	6,662,977
32	General Capital CSP	5,741,801
33	Repl Horizontal Reheater	1,614,783
34	Zimmer LPT Rotor Replacement	3,638,659
35	Other Minor Projects Under $1,000,000	32,273,775
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	172,753,317

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 2010/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	1,998,546,657	1,997,682,287	864,370	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	134,889,926	134,889,926		
4	(403.1) Depreciation Expense for Asset Retirement Costs	4,337,300	4,337,300		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	221,005	219,783	1,222	
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	139,448,231	139,447,009	1,222	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	43,147,102	43,147,102		
13	Cost of Removal	18,584,369	18,584,369		
14	Salvage (Credit)	15,587,287	15,587,287		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	46,144,184	46,144,184		
16	Other Debit or Cr. Items (Describe, details in footnote):	2,448,169	2,448,169		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,094,298,873	2,093,433,281	865,592	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	933,226,496	933,226,496		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	128,596,998	128,596,998		
25	Transmission	244,694,664	244,646,540	48,124	
26	Distribution	747,603,548	746,786,080	817,468	
27	Regional Transmission and Market Operation				
28	General	40,177,167	40,177,167		
29	TOTAL (Enter Total of lines 20 thru 28)	2,094,298,873	2,093,433,281	865,592	

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

Depreciation expense on Monongahela incremental cost	$188,858
Depreciation expense on Conesville Conveyor, account 151	27,305
Depreciation expense on asbestos ARO in account 1080013	3,620
Total	$219,783

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

Depreciation expense on account 105 assets classified to account 421	$1,222

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

RWIP transferred to In-Service	$2,666,406
Asbestos ARO reserve in account 1080013	(33,596)
Transfer between accounts	(184,641)
Total	$2,448,169

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 2010/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	CONESVILLE COAL PREPARATION COMPANY			
2	Common Stock			109,000
3	Premium on Capital Stock			668,589
4	Equity - Undistrubited Earnings			2,064,800
5	Investment in Subsidiary AOCI			-4,325,901
6	Subtotal			-1,483,512
7				
8				
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39				
40				
41				
42	Total Cost of Account 123.1 $ 777,589		TOTAL	-1,483,512

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
		109,000		2
		668,589		3
70,000		2,134,800		4
		-6,166,140		5
70,000		-3,253,751		6
				7
				8
				9
				10
				11
				12
				13
				14
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				41
70,000		-3,253,751		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 2010/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)	72,012,385	70,686,727	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,146,159	2,195,024	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	24,899,970	17,155,917	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	8,010,440	20,675,219	Electric
8	Transmission Plant (Estimated)	311,327	178,726	Electric
9	Distribution Plant (Estimated)	3,596,663	1,322,636	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	523,438	34,360	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	37,341,838	39,366,858	
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)	111,500,382	112,248,609	

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

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

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

Allowances (Accounts 158.1 and 158.2)

1 Report below the particulars (details) called for concerning allowances.
2 Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5 Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2011	
		No (b)	Amt (c)	No (d)	Amt (e)
1	Balance-Beginning of Year	190,219.00	25,028,207	81,528.00	2,918,269
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,732.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Ohio Power Company	28,971.00	6,770,405		
10	Appalachian Power Company	4,417.00	1,149,171		
11	Kentucky Power Company	7,297.00	1,898,460		
12					
13					
14					
15	Total	40,685.00	9,818,036		
16					
17	Relinquished During Year:				
18	Charges to Account 509	38,533.00	4,430,936		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AEP System Pool	19,067.00	3,772,717		
23	I&M Power Company	11,420.00	2,259,633		
24					
25					
26					
27					
28	Total	30,487.00	6,032,350		
29	Balance-End of Year	163,616.00	24,382,957	81,528.00	2,918,269
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		9,714,999		
33	Net Sales Proceeds (Other)		5,967		
34	Gains		3,688,616		
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)		32,429		
45	Gains		32,429		
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 2010/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.

2012		2013		Future Years		Totals		Line
No. (f)	Amt (g)	No. (h)	Amt (i)	No. (j)	Amt (k)	No. (l)	Amt (m)	No.
66,583.00	2,909,101	71,470.00	2,893,530	1,570,331.00	5,818,965	1,980,131.00	39,568,072	1
								2
								3
				59,942.00		61,674.00		4
								5
								6
								7
								8
						28,971.00	6,770,405	9
						4,417.00	1,149,171	10
						7,297.00	1,898,460	11
								12
								13
								14
						40,685.00	9,818,036	15
								16
								17
						38,533.00	4,430,936	18
								19
								20
								21
						19,067.00	3,772,717	22
						11,420.00	2,259,633	23
								24
								25
								26
								27
						30,487.00	6,032,350	28
66,583.00	2,909,101	71,470.00	2,893,530	1,630,273.00	5,818,965	2,013,470.00	38,922,822	29
								30
								31
							9,714,999	32
							5,967	33
							3,688,616	34
								35
856.00		860.00		37,152.00		40,577.00		36
				5,832.00		5,832.00		37
								38
				860.00		1,715.00		39
856.00		860.00		42,124.00		44,694.00		40
								41
								42
								43
					1,781		34,210	44
					1,781		34,210	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 2010/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No	NOx Allowances Inventory (Account 158 1) (a)	Current Year No (b)	Current Year Amt (c)	2011 No (d)	2011 Amt (e)
1	Balance-Beginning of Year	21,179.00	1,544,137	15,902.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,190.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Buckeye Power	872.00	645,435		
10					
11					
12					
13					
14	Other				
15	Total	872.00	645,435		
16					
17	Relinquished During Year:				
18	Charges to Account 509	18,002.00	1,286,798		
19	Other:				
20	Consumption Adjustment				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27	Other				
28	Total				
29	Balance-End of Year	5,239.00	902,774	15,902.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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.

2012		2013		Future Years		Totals		Line No.
No. (f)	Amt (g)	No (h)	Amt (i)	No. (j)	Amt (k)	No (l)	Amt (m)	
15,902.00		15,902.00		15,902.00		84,787.00	1,544,137	1
								2
								3
						1,190.00		4
								5
								6
								7
								8
						872.00	645,435	9
								10
								11
								12
								13
								14
						872.00	645,435	15
								16
								17
						18,002.00	1,286,798	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,902.00		15,902.00		15,902.00		68,847.00	902,774	29
								30
								31
								32
								33
								34
								35
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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 2010/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
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					

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM - IPP R44 Rockport - Impact	18,494	186	33,518	186
3	Sporn-Waterford 345 kV	(2)	186		
4	Buckeye Pwr-Blacklick 138 kV Del			3,114	186
5	PJM-Highland 69 Kv Feasibility	908	186	62	186
6	City of Westerville 138 kV Impact			2,337	186
7	PJM-Bixby 13.8 kV Feasibility Stdy	188	186	188	186
8	Buckeye-Ware Road 138 kV Del	1,746	186	7,500	186
9	PJM-Russelville 138 kV Feasibility	833	186	420	186
10	PJM-Columbus 14.4 kV Feasibility	603	186	37	186
11	PJM-Sporn-Waterford 345 kV Study	130	186		
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	PJM Gen Interconnection Studies	283	500		
23					
24					
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Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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	3,036,314		228.3, 242	126,979	2,909,335
2						
3	DSM Program Costs	4,070,698	8,009,696	Various	9,859,427	2,220,967
4	Ohio ESP - Case No. 08-917-EL-SSO					
5						
6	Unreal Loss on Fwd Commitments		6,956,235	244	4,365,421	2,590,814
7						
8	Deferred Storm Expense	17,014,353				17,014,353
9	Hurricane Ike - Ohio Wind Storm 9/14/08					
10	-Case No. 08-1301-EL-AAM					
11						
12	Deregulation Consumer Education	938,595				938,595
13						
14	Deregulation Transition Filing	902				902
15						
16	Deregulation Implementation	23,410,496	106,253			23,516,749
17						
18	Carrying Charges - Deferred Ohio Deregulation	15,978,925	3,672,741			19,651,666
19						
20	Extension of Local Facilities	56,299,661	15,072,899			71,372,560
21						
22	Reg Asset - Rate Case Expenses	135,489				135,489
23						
24	Deferred Equity Carrying Charges	(12,904,689)	1,339,249	421	3,218,082	-14,783,522
25	(Amort. periods from 01/2005 up to 12/2019)					
26						
27	BridgeCo TO Funding	575,649		407.3	36,464	539,185
28	Per FERC Docket No AC04-101-000					
29	(Amort. period from 01/2005 to 12/2019)					
30						
31	PJM Integration Payments	1,032,713		407.3	175,714	856,999
32	Per FERC Docket No EL05-74-000					
33	(Amort. period from 01/2005 to 12/2014)					
34						
35	Other PJM Integration	537,523		407.3	34,049	503,474
36	Per FERC Docket No AC04-101-000					
37	(Amort. period from 01/2005 to 12/2019)					
38						
39	Carrying Charges - RTO Startup Costs	505,516		407.3	49,840	455,676
40	Per FERC Docket Nos AC04-101-000 & EL05-74-000					
41	(Amort. periods from 01/2005 up to 12/2019)					
42						
43						
44	TOTAL	334,715,592	330,570,065		357,520,922	307,764,735

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 2010/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	Alliance RTO Deferred Expense	470,295		407.3	29,791	440,504
3	Per FERC Docket No AC04-101-000					
4	(Amortization period from 01/2005 to 12/2019)					
5						
6	Def Equity Carrying Charge OH RSP Filing Cost	(45,507)	80,416	421	97,969	-63,060
7						
8	Carrying Charge OH RSP Filing Cost	79,527	26,931			106,458
9						
10	Ohio Line Extension - Equity Charges	(29,709,332)		421	7,953,969	-37,663,301
11						
12	Unrecovered Fuel Cost	36,028,133	73,901,892	501	95,694,224	14,235,801
13	Ohio ESP - Case No. 08-917-EL-SSO					
14						
15	Under-Recovered Ohio TCR Rider		382,185			382,185
16						
17	Carrying Charge - Equity Ohio TCR	(17,148)	17,148			
18	- Docket No. 05-1194-EL-UNC					
19						
20	Carrying Charges - Monongahela Power Acquisition	2,799,786	1,576,092			4,375,878
21						
22	Equity Carrying Charge - Mon Power Acquisition	(1,360,706)		421	818,132	-2,178,838
23						
24	SFAS 158 Employers' Accounting for Defined	175,024,340	173,756,328	Various	175,026,034	173,754,634
25	Benefit Pension and Other Postretirement Plans					
26						
27	Ohio Green Power Pricing Program	151,635	15,346			166,981
28	-Case No 06-1153-EL-UNC					
29						
30	Carry Chgs-Deferred Storm Exp-Hurricane Ike	1,132,583	974,928			2,107,511
31	Ohio Wind Storm - Case No. 08-1301-EL-AAM					
32						
33	Carrying Charges - Ohio Fuel Adjustment Clause	1,880,899	1,885,422	421	172,991	3,593,330
34	Ohio ESP - Case No. 08-917-EL-SSO					
35						
36	Under-Recovered Enhanced SVC Reliability Plan Costs	2,061,213	3,196,546	593	2,268,009	2,989,750
37	Ohio ESP - Case No. 08-917-EL-SSO					
38						
39	EDR - Carrying Charges	59,668	650,486	421	10	710,144
40	- EDR - Economic Development Rider					
41	- Case No. 09-119-EL-AEC					
42						
43						
44	TOTAL	334,715,592	330,570,065		357,520,922	307,764,735

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	EDR - Deferral	10,149,519	5,437,888	555	15,587,407	
3	- EDR - Economic Development Rider					
4	- Case Nos. 09-119-EL-AEC & 09-516-EL-AEC					
5						
6	EDR - Excess Cap Deferral		3,000,000			3,000,000
7						
8	EDR - Carrying Chgs - Excess Cap Deferral		57,300			57,300
9						
10	Def Eqty Carrying Chgs - OH FAC - Current			421	1,798,596	-1,798,596
11	-Ohio ESP-Case No. 08-917-EL-SSO					
12						
13	SFAS 109 Deferred FIT	12,133,090	29,050,324	Various	36,053,639	5,129,775
14						
15	SFAS 109 Deferred SIT	1,541,044	139,114	283.3	1,473,411	206,747
16						
17	Monongahela Power Integration Cost	4,791,210	1,054,544	Various	113,382	5,732,372
18						
19	Monongahela Power Litigation Termination	2,861,072	210,102	407.3	2,567,382	503,792
20	-Case No 05-765-EL-UNC					
21						
22	Monongahela Power Acqd Net Reg Asset	4,052,126				4,052,126
23						
24						
25						
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32						
33						
34						
35						
36						
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38						
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41						
42						
43						
44	TOTAL	334,715,592	330,570,065		357,520,922	307,764,735

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 2010/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	8,155	805,376	Various	812,694	837
2						
3	Deferred Property Taxes	97,313,929	114,277,040	Various	101,813,929	109,777,040
4						
5	Agency Fees - Factored A/R	3,381,894	35,964,666	Various	35,826,615	3,519,945
6						
7	Defd Prop Tax - Capital Leases	250	263,620	408.1	263,620	250
8						
9	CCPC Coal Washing Costs	22,097	7,395,620	151	7,417,717	
10						
11	Nontraditional Option Premiums	62,477	127,557	232	190,034	
12						
13	Unamortized Credit Line Fees	70,343	484,916	431	137,318	417,941
14						
15	Defd Depr&Capcty Portion-Affil	8,186,558	1,837,548			10,024,106
16						
17	Deferred Expenses - Current	5,872	66,503	Various	64,748	7,627
18						
19	Defd Lease Assets - Non Taxable	12,119	1,350,959	Various	1,276,693	86,385
20						
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46						
47	Misc. Work in Progress	772,076				752,523
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	109,835,770				124,586,654

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 2010/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	26,292,177	27,631,353
4	Mark to Market	-8,460,215	-6,196,254
5	Contribution in Aid of Construction	15,206,883	13,692,436
6	SEC Allocation of Investment Tax Credit - Generation Plant	5,678,766	5,228,899
7	Other	49,592,222	71,108,893
8	TOTAL Electric (Enter Total of lines 2 thru 7)	88,624,833	111,780,327
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	30,335,378	24,818,166
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	118,960,211	136,598,493

Notes

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Line 17 Other - Detail              Beginning Balance          Ending Balance

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Non-Utility - 190.2                  3,878,545                  3,396,208
SFAS 109 - 190.3 & 190.4             1,435,380                 -2,980,730
SFAS 133 - 190.0006                    633,252                    152,143
SFAS 87 - 190.0009                  24,388,201                 24,250,545

                                    ----------                -----------
                                    30,335,378                 24,818,166

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

Balance at Beginning of Year                                     $118,960,211

(Less) Amounts Debited to:
  (a) Account 410.1                                               (37,177,221)
  (b) Account 410.2                                                (2,829,731)
  (c) Various                                                     (37,244,636)

(Plus) Amounts Credited to:
  (a) Account 411.1                                                60,332,716
  (b) Account 411.2                                                 2,347,394
  (c) Various                                                      32,209,760

Balance at End of Year                                           $136,598,493
```

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 2010/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			
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Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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
						4
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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 2010/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	-1,681,289
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	48,017
11	Subtotal	-1,533,451
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		
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39		
40	TOTAL	322,920,065

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 2010/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		
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21		
22	TOTAL	

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - BONDS		
2	NONE		
3			
4	ACCOUNT 222 - REACQUIRED BONDS		
5	NONE		
6			
7	SUBTOTAL (ACCOUNT 222)		
8			
9	ACCOUNT 223 - ADVANCES FROM ASSOC COMPANIES		
10			
11	4.64% Notes Payable Affiliated Due 2010	100,000,000	
12			
13	SUBTOTAL (ACCOUNT 223)	100,000,000	
14			
15	ACCOUNT 224 - OTHER LONG-TERM DEBT		
16			
17	5.50% Unsecured Medium Term Notes Series A Due 2013	250,000,000	1,625,000
18			657,500 D
19			
20	6.60% Unsecured Medium Term Notes Series B Due 2033	250,000,000	2,187,500
21			1,180,000 D
22			
23	4.40% Unsecured Medium Term Notes Series E Due 2010	150,000,000	937,500
24			315,000 D
25			
26	5.85% Unsecured Medium Term Notes Series F Due 2035	250,000,000	2,187,500
27			2,815,000 D
28			
29	6.05% Unsecured Medium Term Notes Series G Due 2018	350,000,000	2,347,096
30			791,000 D
31			
32			
33	TOTAL	1,542,745,000	18,732,729

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 2010/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	Floating Rate Unsecured Notes Series A Due 2012		556,619
3	PUCO Case No. 09-314-EL-AIS dated 04/09/2009		
4			
5	Ohio Air Quality Revenue Bonds 4.85% Series 2007A Due 2040	44,500,000	928,466
6	*Bond subject to mandatory tender for purchase (puttable) on 05/01/12		
7			
8	Ohio Air Quality Revenue Bonds 5.10% Series 2007B Due 2042	56,000,000	1,101,717
9	*Bond subject to mandatory tender for purchase (puttable) on 05/01/13		
10			
11	Ohio Air Quality Revenue Bonds 3.875% Series 2009A Due 2038	60,000,000	656,061
12	*Bond subject to mandatory tender for purchase (puttable) on 06/01/14		
13			
14	Ohio Air Quality Revenue Bonds 5.80% Series 2009B Due 2038	32,245,000	446,770
15			
16			
17	Brokerage Fees on Auction Rate Notes		
18			
19	SUBTOTAL (ACCOUNT 224)	1,442,745,000	18,732,729
20			
21	Footnote		
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,542,745,000	18,732,729

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
08/18/04	03/15/10				966,667	11
						12
					966,667	13
						14
						15
						16
02/14/03	03/01/13	02/14/03	03/01/13	250,000,000	13,750,000	17
						18
						19
02/14/03	03/01/33	02/14/03	03/01/33	250,000,000	16,500,000	20
						21
						22
11/25/03	12/01/10	11/25/03	12/01/10		6,050,000	23
						24
						25
10/14/05	10/01/35	10/14/05	10/01/35	250,000,000	14,625,000	26
						27
						28
05/16/08	05/01/18	05/16/08	05/01/18	350,000,000	21,175,000	29
						30
						31
						32
				1,442,745,000	83,196,386	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 2010/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)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
03/16/10	03/16/2012	03/16/2010	03/16/2012	150,000,000	920,259	2
						3
						4
08/15/07	08/01/40	08/15/07	05/01/12	44,500,000	2,158,250	5
						6
						7
11/20/07	11/01/42	11/20/07	05/01/13	56,000,000	2,856,000	8
						9
						10
08/19/09	12/01/38	08/19/09	06/01/14	60,000,000	2,325,000	11
						12
						13
08/19/09	12/01/38	08/19/09	12/01/38	32,245,000	1,870,210	14
						15
						16
						17
						18
				1,442,745,000	82,229,719	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,442,745,000	83,196,386	33

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

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.

Schedule Page: 256.1 Line No.: 8 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.: 11 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.: 21 Column: a

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

Name of Respondent	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 2010/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)	230,222,375
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	234,280,008
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Columbus Southern Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2010/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 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

(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 2010/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	-28,372,080		53,478,134	34,599,676	
3	FICA - 2010	423,052		7,584,095	7,158,388	
4	Unemployment - 2010	11,813		77,890	73,996	
5	Payroll Taxes - CCD			973,483	973,483	
6	Federal Excise Tax - 2010			2,623	2,623	
7	SUBTOTAL	-27,937,215		62,116,225	42,808,166	
8						
9	State of Ohio:					
10	KWH Ohio Excise-2009	5,899,279			5,899,279	
11	KWH Ohio Excise-2010			71,692,506	65,657,051	
12	OCC & PUCO FEES-2010			2,672,152	2,672,152	
13	Ohio CAT Tax - 2009	1,201,500		-149,337	1,052,163	
14	Ohio CAT Tax - 2010			5,705,995	4,340,005	
15	Sales & Use - 2009	227,629	65,000	-102,420	60,209	
16	Sales & Use - 2010			809,121	597,599	
17	Sales & Use - Prov&Audit	100,000		-1,105,208	-1,005,208	
18	Unemployment - OH 2010	20,925		132,169	130,629	
19	Ohio Income Tax - Prior			2,743	2,743	
20	Ohio Franch 2009 & Prior					
21	Ohio City Tax - 2008 & Prior			-5,988	-5,988	
22	Ohio City Tax - 2009	-973,393		-267,330	-1,240,723	
23	Ohio City Tax - 2010			2,737,567	2,977,481	
24	SUBTOTAL	6,475,940	65,000	82,121,970	81,137,392	
25	KY Cities					
26	KY Income Tax - 2007 & Prior					
27	KY Income Tax - 2009	-415,277		-20,816	-436,093	
28	KY Income Tax - 2010			43,466	136,810	
29	SUBTOTAL	-415,277		22,650	-299,283	
30						
31	WV Income Tax-2009	72,084		-72,101	-17	
32	WV Income Tax-2010			123	323,000	
33	WV Fran Tax - 2009 & Prior	-55,351		-217,936	-273,287	
34	WV Fran Tax - 2010					
35	SUBTOTAL	16,733		-289,914	49,696	
36						
37						
38						
39						
40	Real & Pers. Prop - 2008 OH	91,408,730		-138,684	91,270,046	
41	TOTAL	167,830,218	65,000	260,246,492	215,514,312	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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 - 2009 OH	97,277,929		4,500,000		
2	Real & Pers. Prop - 2010 OH			109,739,040		
3						
4	Pers Prop Leased-2005 OH	85,280		-85,280		
5	Pers Prop Leased-2009 OH	300,000				
6	Pers Prop Leased-2010 OH			263,120		
7						
8	Pers Prop Leased-2009 WV	500		-121	379	
9	Pers Prop Leased-2010 WV			500		
10						
11	Real Prop Leased - 2009 OH	22,836		-11,711	11,125	
12	Real Prop Leased - 2010 OH			10,698		
13						
14	Real & Pers Prop - 2008 KY			170	170	
15	Real & Pers Prop - 2009 KY	36,000			38,311	
16	Real & Pers Prop - 2010 KY			38,000		
17						
18	Real & Pers. Prop - 2010 LA			485	485	
19	SUBTOTAL	189,131,275		114,316,217	91,320,516	
20						
21	Other Than Income Tax:					
22	State Lic Tax 2009 & Prior					
23	State Lic Tax 2010			25	25	
24	Multi Fran Tax 2010			600	600	
25	SUBTOTAL			625	625	
26						
27	Fed Inc Tx- FIN48	-101,413		-244,604		
28	State Inc Tx- FIN48	18,275		2,383,725		
29	SUBTOTAL	-83,138		2,139,121		
30	MI Income - 2009	576,955		-340,755	236,200	
31	MI Income - 2010			158,251	261,000	
32	SUBTOTAL	576,955		-182,504	497,200	
33						
34						
35	Illinois Income - 2009	64,945		-77,773	-12,828	
36	Illinois Income - 2010			79,875	12,828	
37	SUBTOTAL	64,945		2,102		
38						
39						
40						
41	TOTAL	167,830,218	65,000	260,246,492	215,514,312	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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
-9,493,622		57,706,893			-4,228,759	2
848,759		5,101,991			2,482,104	3
15,707		54,476			23,414	4
		973,483				5
		2,623				6
-8,629,156		63,839,466			-1,723,241	7
						8
						9
						10
6,035,455		71,692,506				11
		2,672,152				12
		-149,337				13
1,365,990		5,705,995				14
		207			-102,627	15
271,522	60,000	3,785			805,336	16
		-486,608			-618,600	17
22,465		87,932			44,237	18
		2,743				19
						20
		-5,988				21
		-273,513			6,183	22
-239,914		2,627,704			109,863	23
7,455,518	60,000	81,877,578			244,392	24
						25
						26
		-19,130			-1,686	27
-93,344		41,812			1,654	28
-93,344		22,682			-32	29
						30
		-52,382			-19,719	31
-322,877		116			7	32
		-217,936				33
						34
-322,877		-270,202			-19,712	35
						36
						37
						38
						39
		-138,684				40
212,557,398	60,000	249,245,475			11,001,017	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
101,777,929		101,743,129			-97,243,129	1
109,739,040					109,739,040	2
						3
		-85,280				4
300,000						5
263,120		263,120				6
						7
		129			-250	8
500		250			250	9
						10
		-11,711				11
10,698		10,698				12
						13
		170				14
-2,311		36,000			-36,000	15
38,000					38,000	16
						17
		485				18
212,126,976		101,818,306			12,497,911	19
						20
						21
						22
		25				23
		600				24
		625				25
						26
-346,017		-244,604				27
2,402,000		2,383,725				28
2,055,983		2,139,121				29
		-340,755				30
-102,749		158,251				31
-102,749		-182,504				32
						33
						34
		-76,412			-1,361	35
67,047		76,815			3,060	36
67,047		403			1,699	37
						38
						39
						40
212,557,398	60,000	249,245,475			11,001,017	41

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	2,604			4114	2,604	
4	7%						
5	10%	16,830,355			4114	2,042,995	
6							
7							
8	TOTAL	16,832,959				2,045,599	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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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 2010/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
	Various		3
			4
14,787,360	Various		5
			6
			7
14,787,360			8
			9
			10
			11
			12
			13
			14
			15
			16
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			18
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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 2010/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	780,125	253	744,854		35,271
2						
3	Customer Advance Receipts	4,272,459	142	47,297,278	47,236,318	4,211,499
4						
5	Deferred Rev - Pole Attachments	250,783	Various	1,904,021	1,787,601	134,363
6						
7	SFAS 106 - OPEB	6,715,126	Various	611,687	291,520	6,394,959
8						
9	MACSS Unidentified EDI Cash	6,078	Various	1,894,264	1,891,368	3,182
10						
11	Other Deferred Credit-Current	298,452	Various	131,384	2,575,445	2,742,513
12						
13	State Mitigation Deferral (NSR)	1,845,024	242	922,512		922,512
14						
15	Federal Mitigation Deferrel (NSR)	4,034,837				4,034,837
16						
17	Customer Choice Collateral Deposit				520,000	520,000
18						
19	Fiber Optic Lines-Sold-Defd Rev	1,507,171	451	114,731		1,392,440
20	(Various amortization periods					
21	up to 12/2024)					
22						
23						
24						
25						
26						
27						
28						
29						
30						
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33						
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43						
44						
45						
46						
47	TOTAL	19,710,055		53,620,731	54,302,252	20,391,576

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 2010/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	19,682,408	13,872,600	477,369
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	19,682,408	13,872,600	477,369
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)	19,682,408	13,872,600	477,369
18	Classification of TOTAL			
19	Federal Income Tax	19,682,408	13,872,600	477,369
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 2010/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.
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
							2
							3
						33,077,639	4
							5
							6
							7
						33,077,639	8
							9
							10
							11
							12
							13
							14
							15
							16
						33,077,639	17
							18
						33,077,639	19
							20
							21

NOTES (Continued)

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	530,382,766	127,827,452	38,606,266
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	530,382,766	127,827,452	38,606,266
6	Non-Utility	-1,451,287		
7	SFAS 109	5,739,462		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	534,670,941	127,827,452	38,606,266
10	Classification of TOTAL			
11	Federal Income Tax	534,670,941	127,827,452	38,606,266
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				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
						619,603,952	2
							3
							4
						619,603,952	5
	1,939					-1,453,226	6
		Various	22,725,845	Various	15,031,243	-1,955,140	7
							8
	1,939		22,725,845		15,031,243	616,195,586	9
							10
	1,939		22,725,845		15,031,243	616,195,586	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 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Emission Allowances	9,676,026	3,527,119	2,725,077
4	Capitalized Software	6,292,397	438,266	1,527,082
5	Pension Expense	-11,469,391	2,121,477	992,373
6	Mark to Market	9,603,346	16,612,318	13,535,898
7	Loss on Reacquired Debt	3,274,926		260,239
8	Other	120,215,419	30,965,372	34,259,134
9	TOTAL Electric (Total of lines 3 thru 8)	137,592,723	53,664,552	53,299,803
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other NonUtility/SFAS 109&133	-7,066,414		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	130,526,309	53,664,552	53,299,803
20	Classification of TOTAL			
21	Federal Income Tax	121,303,011	52,333,620	51,574,786
22	State Income Tax	9,223,298	1,330,932	1,725,017
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 2010/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						10,478,068	3
						5,203,581	4
						-10,340,287	5
						12,679,766	6
						3,014,687	7
						116,921,657	8
						137,957,472	9
							10
							11
							12
							13
							14
							15
							16
							17
734,526	5,217,187	Various	16,482,663	Various	11,879,522	-16,152,216	18
734,526	5,217,187		16,482,663		11,879,522	121,805,256	19
							20
734,526	5,217,187		15,009,252		11,740,408	114,310,340	21
			1,473,411		139,114	7,494,916	22
							23

NOTES (Continued)

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	(13,824,598)	(18,307,257)
SFAS 109	6,326,991	2,074,530
SFAS 133	431,193	80,511
Total	$ (7,066,414)	$(16,152,216)

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	Ohio RSP-Low Income Customer / Econ Recovery	2,351,000	232	91,277		2,259,723
2	Docket No. 04-169-EL-UNC					
3						
4	Over-Recovered Ohio TCR Rider	14,810,930	447	24,738,520	9,927,590	
5	Docket No. 05-1194-EL-UNC					
6						
7	Carrying Charge - Over-Recovered Ohio TCR	376,683	Various	427,231	836,791	786,243
8	Docket No. 05-1194-EL-UNC					
9						
10	IGCC Pre-Construction Costs Net Recovery	1,823,276	182.3	5,991	117	1,817,402
11	Docket No. 05-376-EL-UNC					
12						
13	Over-Recovered gSMART Misc Dist Expense	3,785,738	588	5,276,894	6,529,353	5,038,197
14	Ohio ESP - Case No. 08-917-EL-SSO					
15						
16	Over-Recovered gSMART Debt Carrying Charge	833,154	431	765,902	52,447	119,699
17	Ohio ESP - Case No. 08-917-EL-SSO					
18						
19	Over-Recovered gSMART Equity Carrying Charge	721,356	426.5	575,547	53,606	199,415
20	Ohio ESP - Case No. 08-917-EL-SSO					
21						
22	Over-Recovered gSMART Depr / A&G Expense	2,136,506	403, 930.2	2,137,801	825,776	824,481
23	Ohio ESP - Case No. 08-917-EL-SSO					
24						
25	Over-Recovery EDR Deferral				335,645	335,645
26	- EDR - Economic Development Rider					
27	- Case Nos. 09-119-EL-AEC & 09-516-EL-AEC					
28						
29	SFAS 109 Deferred FIT	3,043,061	Various	818,998	12,339	2,236,402
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	29,881,704		34,838,161	18,573,664	13,617,207

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 2010/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	883,766,072	749,622,708
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	751,724,082	715,726,606
5	Large (or Ind.) (See Instr. 4)	256,780,153	267,791,467
6	(444) Public Street and Highway Lighting	7,053,444	6,341,432
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,899,323,751	1,739,482,213
11	(447) Sales for Resale	326,948,116	281,037,292
12	TOTAL Sales of Electricity	2,226,271,867	2,020,519,505
13	(Less) (449.1) Provision for Rate Refunds	50,000,000	
14	TOTAL Revenues Net of Prov. for Refunds	2,176,271,867	2,020,519,505
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,665,604	2,827,686
17	(451) Miscellaneous Service Revenues	1,878,089	2,259,332
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	20,077,352	17,232,043
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,524,459	783,438
22	(456.1) Revenues from Transmission of Electricity of Others	15,322,291	13,478,421
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	42,467,795	36,580,920
27	TOTAL Electric Operating Revenues	2,218,739,662	2,057,100,425

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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
7,804,465	7,303,192	667,001	667,018	2
				3
8,709,367	8,532,204	78,647	78,482	4
4,666,295	4,783,906	3,320	3,384	5
54,925	54,167	307	308	6
				7
				8
				9
21,235,052	20,673,469	749,275	749,192	10
6,397,937	5,862,120	102	103	11
27,632,989	26,535,589	749,377	749,295	12
				13
27,632,989	26,535,589	749,377	749,295	14

Line 12, column (b) includes $ 11,272,267 of unbilled revenues.
Line 12, column (d) includes 126,317 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	2,450,929	11,050	15,188
(442) Commercial	10,130,140	51,351	11,775
(442) Industrial	381,921	2,299	416
(444) Street Lighting	7,045,117	54,927	307
	20,008,107	119,627	27,686

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

Miscellaneous Service Revenue, including connects, reconnects, disconnects, temporary services and other charges billed to customer.

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

Ohio Line Extention Construction	3,599,408
Financial Trading Revenue - Unrealized	-3,500,820
Coal Trading Realized - Gain/Loss	2,022,231
Associated Business Development	792,732
MTM Credit Risk Reserve	-661,755
MTM Affliated Coal Trading - Gain/Loss	274,453
All other under $250,000 each	-1,790
	2,524,459

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 2010/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					
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38					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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	RR Residential Service	6,799,335	764,796,494	494,907	13,739	0.1125
3	RR-1 Res Small Use Load Mgt	927,117	107,375,481	172,010	5,390	0.1158
4	RLM Res Optional Demand Rate	6,387	561,211	70	91,243	0.0879
5	RS-ES Res Energy Storage	17	2,088	2	8,500	0.1228
6	RS-TOD Res Time-of-Day	62	6,905	7	8,857	0.1114
7	GS-1 General Service-Small	1	143			0.1430
8	GS-2 Gen Svc-Low Load Factor	20	2,354			0.1177
9	AL Private Area Lighting	11,050	2,450,929			0.2218
10	OAD-RR Open Access Res Svc	39	2,024	5	7,800	0.0519
11	OAD-AL Open Acc Priv Area Light	3	284			0.0947
12	Subtotal-Billed	7,744,031	875,197,913	667,001	11,610	0.1130
13	Net Unbilled	60,434	8,568,159			0.1418
14	Total-Residential	7,804,465	883,766,072	667,001	11,701	0.1132
15						
16						
17	442-Commercial					
18	RR Residential Service	-2	-96			0.0480
19	RR-1 Res Small Use Load Mgt	1	180			0.1800
20	GS-1 General Service-Small	339,347	46,160,514	49,812	6,813	0.1360
21	GS-2 Gen Svc-Low Load Factor	1,479,107	175,567,521	22,078	66,995	0.1187
22	GS-2-TOD Gen Svc- Time-of-Day	10,547	1,052,354	115	91,713	0.0998
23	GS-3 Gen Svc-Med Load Factor	5,335,584	453,774,064	4,903	1,088,228	0.0850
24	GS-4 General Service-Large	890,653	47,999,228	11	80,968,455	0.0539
25	SL Street Lighting	264	21,990	3	88,000	0.0833
26	AL Private Area Lighting	41,196	9,095,085			0.2208
27	OAD-GS-1 Open Access GS-Small	4,638	169,592	262	17,702	0.0366
28	OAD-GS-2 Open Acc GS-Low Load	154,151	4,343,180	1,027	150,098	0.0282
29	OAD-GS-3 Open Acc GS-Med Load	375,459	9,006,581	430	873,160	0.0240
30	OAD-GS-4 Open Acc GS-Large Load	1,489	11,599			0.0078
31	OAD-AL Open Acc Priv Area Light	90	7,383			0.0820
32	IRP-D Interruptible Power Discret	2,268	322,952	1	2,268,000	0.1424
33	Net Estimated Billings	14,866	1,190,974	5	2,973,200	0.0801
34	Subtotal-Billed	8,649,658	748,723,101	78,647	109,981	0.0866
35	Net Unbilled	59,709	3,000,981			0.0503
36	Total-Commercial	8,709,367	751,724,082	78,647	110,740	0.0863
37						
38						
39						
40						
41	TOTAL Billed	21,108,735	1,888,051,484	749,275	28,172	0.0894
42	Total Unbilled Rev.(See Instr. 6)	126,317	11,272,267	0	0	0.0892
43	TOTAL	21,235,052	1,899,323,751	749,275	28,341	0.0894

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6	442-Industrial					
7	GS-1 General Service-Small	8,780	1,236,190	1,655	5,305	0.1408
8	GS-2 Gen Svc-Low Load Factor	147,995	18,396,420	1,108	133,569	0.1243
9	GS-2-TOD Gen Svc- Time-of-Day	254	27,670	1	254,000	0.1089
10	GS-3 Gen Svc-Med Load Factor	1,312,757	105,799,774	434	3,024,786	0.0806
11	GS-4 General Service-Large	2,884,413	118,438,349	23	125,409,261	0.0411
12	AL Private Area Lighting	2,251	376,784			0.1674
13	IRP-D Interruptible Power Discret	13,399	772,612	1	13,399,000	0.0577
14	OAD-GS-1 Open Access GS-Small	138	5,312	10	13,800	0.0385
15	OAD-GS-2 Open Acc GS-Low Load	24,173	782,156	61	396,279	0.0324
16	OAD-GS-3 Open Acc GS-Med Load	64,337	1,343,336	25	2,573,480	0.0209
17	OAD-GS-4 Open Acc Gs-Large Load	4,699	37,327			0.0079
18	OAD-AL Open Acc Priv Area Light	6	462			0.0770
19	Net Estimated Billings	196,917	9,868,961	2	98,458,500	0.0501
20	Subtotal-Billed	4,660,119	257,085,353	3,320	1,403,650	0.0552
21	Net Unbilled	6,176	-305,200			-0.0494
22	Total-Industrial	4,666,295	256,780,153	3,320	1,405,511	0.0550
23						
24						
25	444-Street & Highway Lighting					
26	GS-1 General Service-Small	13,509	1,332,980	98	137,847	0.0987
27	SL Street Lighting	41,418	5,712,137	209	198,172	0.1379
28	Subtotal-Billed	54,927	7,045,117	307	178,915	0.1283
29	Net Unbilled	-2	8,327			-4.1635
30	Total-Str & Highway Lighting	54,925	7,053,444	307	178,909	0.1284
31						
32						
33	Fuel Adj Clause - See Footnote					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	21,108,735	1,888,051,484	749,275	28,172	0.0894
42	Total Unbilled Rev.(See Instr. 6)	126,317	11,272,267	0	0	0.0892
43	TOTAL	21,235,052	1,899,323,751	749,275	28,341	0.0894

Schedule Page: 304.1 Line No.: 33 Column: a

Fuel Adjustment Clause - Estimated Additional Revenue

440-Residential	
RR Residential Service	245,335,225
RR-1 Res Small Use Load Mgt	33,462,662
RLM Res Optional Demand Rate	229,692
RS-ES Res Energy Storage	618
RS-TOD Res Time-of-Day	2,224
GS-1 General Service - Small	35
GS-2 Gen Svc - Low Load Factor	720
AL Private Area Lighting	499,061
Total Billed	279,530,237
Unbilled	3,917,945
Total	283,448,182
442-Commercial	
RR Residential Service	-77
RR-1 Res Small Use Load Mgt	32
GS-1 General Service - Small	12,277,862
GS-2 Gen Svc - Low Load Factor	53,266,438
GS-2-TOD Gen Svc - Time-of-Day	379,925
GS-3 Gen Svc - Med Load Factor	181,774,675
GS-4 General Service - Large	27,581,965
IRP-D Interruptible Power Discretionary	70,316
SL Street Lighting	10,493
AL Private Area Lighting	1,860,902
Net Estimated Billings	502,115
Total Billed	277,724,646
Unbilled	1,381,566
Total	279,106,212
442-Industrial	
GS-1 General Service - Small	317,636
GS-2 Gen Svc - Low Load Factor	5,293,119
GS-2-TOD Gen Svc - Time-of-Day	8,781
GS-3 Gen Svc - Med Load Factor	44,136,441
GS-4 General Service - Large	89,476,097
IRP-D Interruptible Power Discretionary	412,518
AL Private Area Lighting	102,728
Net Estimated Billings	6,073,365
Total Billed	145,820,685
Unbilled	-86,834
Total	145,733,851
444-Street & Highway Lighting	
GS-1 General Service - Small	490,205
SL Street Lighting	1,642,825
Total Billed	2,133,030
Unbilled	5,964
Total	2,138,994
Total	710,427,239

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.
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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	AEP Service Corporation	OS	20			
2	AEP Service Corporation	OS	30			
3	Allegheny Electric Cooperative	OS	Note 1			
4	ALLETE, Inc. dba Minnesota Pwr	OS	Note 1			
5	Ameren Energy Marketing	OS	Note 1			
6	American Municipal Power-Ohio	OS	Note 1			
7	Associated Elect Cooperative	OS	Note 1			
8	B.P. Energy Company	OS	Note 1			
9	Baltimore Gas & Electric	OS	Note 1			
10	Barclays Bank PLC	OS	Note 1			
11	Beech Ridge Energy LLC	OS	Note 1			
12	Big Rivers Electric Corp	OS	Note 1			
13	BP AMOCO	OS	Note 1			
14	Buckeye Rural Electric Admin	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 2010/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).
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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	Calpine Power Service Company	OS	Note 1			
2	Carolina Power & Light	OS	Note 1			
3	Central Illinois	OS	Note 1			
4	Central Illinois Public Svc Co	OS	Note 1			
5	Citigroup Energy Inc.	OS	Note 1			
6	Citizens Elect Co & Wellsborough	OS	Note 1			
7	City of Batavia	OS	Note 1			
8	City of Columbus	OS	Note 1			
9	City of Croswell, MI	OS	Note 1			
10	City of Dowagiac, MI	OS	Note 1			
11	City of Lebanon	OS	Note 1			
12	City of Philippi, West Virgini	OS	Note 1			
13	City of Westerville	OS	Note 1			
14	Cleco Utility Group LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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 2010/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).
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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	Cleveland Public Power	OS	Note 1			
2	Commonwealth Edison Company	OS	Note 1			
3	Conectiv Energy Supply Inc.	OS	Note 1			
4	Conoco Inc.	OS	Note 1			
5	Constellation Engy Commodities	OS	Note 1			
6	Cook Inlet Energy Supply LP	OS	Note 1			
7	Credit Suisse Energy	OS	Note 1			
8	Delaware Electric Municipal Co	OS	Note 1			
9	Delmarva Power & Light	OS	Note 1			
10	DP&L Power Services	OS	Note 1			
11	DTE Energy Trading Inc.	OS	Note 1			
12	Duke Energy Carolinas, LLC	OS	Note 1			
13	Duke Energy Indiana, Inc.	OS	Note 1			
14	Duke Energy Kentucky, Inc.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Duquesne Power, L.P.	OS	Note 1			
2	Dynegy Power Marketing Inc.	OS	Note 1			
3	East KY Power Co-Op Power Mktg	OS	Note 1			
4	EDF Trading North America LLC	OS	Note 1			
5	Edison Mission Mktg & Trading	OS	Note 1			
6	Endure Energy, LLC	OS	Note 1			
7	Energy America, LLC	OS	Note 1			
8	Eng Mktg, div of Amerada Hess	OS	Note 1			
9	Entergy Power Serv	OS	Note 1			
10	Exelon Generation - Power Team	OS	Note 1			
11	FirstEnergy Trading Services	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 2010/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).
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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	HETC	OS	Note 1			
2	Hoosier Power Market	OS	Note 1			
3	Illinois Municipal Elec Agency	OS	Note 1			
4	Illinois Power Company	OS	Note 1			
5	Indiana Municipal Power Agency	OS	Note 1			
6	Indianapolis Power & Light Co	OS	Note 1			
7	Integrys Energy Services, Inc	OS	Note 1			
8	Interstate Power & Light Co	OS	Note 1			
9	J ARON & Company	OS	Note 1			
10	JP Morgan Ventures Energy Corp	OS	Note 1			
11	Kansas City Power & Light Co	OS	Note 1			
12	Kentucky Municipal Power Agncy	OS	Note 1			
13	Letterkenny Industril Dev Auth	OS	Note 1			
14	LG&E Utilities Power Sales	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Louis Dreyfus Energy Serv LP	OS	Note 1			
2	Michigan Public Power Agency	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	No Carolina Muni Pwr Agency #1	OS	Note 1			
11	Nordic Energy Services, LLC	OS	Note 1			
12	NRG Power Marketing Inc.	OS	Note 1			
13	Ohio Retail	OS	Note 1			
14	Old Dominion Elec.	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 2010/Q4

SALES FOR RESALE (Account 447)

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Rainbow Energy Marketing	OS	Note 1			
2	Sempra Energy Solutions, LLC	OS	Note 1			
3	Sempra Energy Trading	OS	Note 1			
4	Shell Energy N America (US) LP	OS	Note 1			
5	South Carolina Electric & Gas	OS	Note 1			
6	Southeastern Pub Serv Auth -VA	OS	Note 1			
7	Southen Maryland Elec Coop Inc	OS	Note 1			
8	Southern Company	OS	Note 1			
9	Southern Illinois Power Co-Op	OS	Note 1			
10	Tenaska Power Services Company	OS	Note 1			
11	The Borough of Pitcairn, PA	OS	Note 1			
12	The Energy Authority	OS	Note 1			
13	The Potomac Edison Company	OS	Note 1			
14	Town of Front Royal	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 2010/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	Town of Hagerstown, Indiana	OS	Note 1			
2	TVA Bulk Power Trading	OS	Note 1			
3	UBS Securities LLC	OS	Note 1			
4	Union Electric Company	OS	Note 1			
5	Union Power Partners	OS	Note 1			
6	Village of Sebewaing, MI	OS	Note 1			
7	Wabash Valley Power Assn Inc.	OS	Note 1			
8	Washington Gas Energy Services	OS	Note 1			
9	Westar Energy Inc.	OS	Note 1			
10	Wisconsin Power & Light	OS	Note 1			
11	Wolverine Power Supply Coop	OS	Note 1			
12	Adjustment					
13						
14						
	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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
53,090		1,937,765		1,937,765	1
2,019,752	769,329	63,696,981		64,466,310	2
70,574		4,724,359		4,724,359	3
28,329		776,173		776,173	4
-321		117,729		117,729	5
73,504		4,675,344		4,675,344	6
-3,536		-121,821		-121,821	7
13,405		438,242		438,242	8
90,931		7,158,081		7,158,081	9
61,186		4,389,605		4,389,605	10
		-21,714		-21,714	11
-8					12
		273,179		273,179	13
64,300	-28,581	29,528,492		29,499,911	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-17,871		-654,865		-654,865	1
262		-930,507	943,759	13,252	2
		10,552		10,552	3
		20,483		20,483	4
-7,014		-1,279,074		-1,279,074	5
9,982		452,923		452,923	6
12,096		856,697		856,697	7
162,352		10,526,677		10,526,677	8
1,767		74,681		74,681	9
		203,260		203,260	10
59,488		4,027,831		4,027,831	11
		-9		-9	12
52,997	102,638	4,281,480		4,384,118	13
-227		-7,250		-7,250	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
30,074		1,604,546		1,604,546	1
32,333		1,285,698		1,285,698	2
		6,002		6,002	3
-11,845		-648,096		-648,096	4
77,067		2,987,365		2,987,365	5
		127,221		127,221	6
119,803		3,992,636		3,992,636	7
82,712		5,525,534		5,525,534	8
54,830		4,416,429		4,416,429	9
3,476		-16,525		-16,525	10
-3,796		-494,441		-494,441	11
180		-10,968		-10,968	12
		-3,866		-3,866	13
		-879		-879	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
85,032		3,907,372		3,907,372	1
		15,383		15,383	2
		-32		-32	3
-18,982		-827,218		-827,218	4
64,418		2,239,895		2,239,895	5
1,503		30,820		30,820	6
13,567		658,222		658,222	7
124,518		5,940,168		5,940,168	8
5,982		241,776		241,776	9
-318,287		-14,864,000		-14,864,000	10
442,818		27,451,820		27,451,820	11
		35,367		35,367	12
17,180		1,203,150		1,203,150	13
		-7,448		-7,448	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-3		-3	1
-17,597		-672,378		-672,378	2
2,316	13,908	161,146		175,054	3
		31,035		31,035	4
36,409	41,481	1,587,246		1,628,727	5
	2,814			2,814	6
6,735		947,213		947,213	7
-44,938		92,171		92,171	8
470,280		18,663,178		18,663,178	9
250,622		10,104,326		10,104,326	10
-13,653		-468,473		-468,473	11
65,570		3,914,359		3,914,359	12
14,652		974,017		974,017	13
2,275		101,578		101,578	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-9		-9	1
10,803		537,166		537,166	2
150,532		7,041,234		7,041,234	3
18,390		-1,836,148		-1,836,148	4
		-7,857		-7,857	5
		1,447,244		1,447,244	6
-138,519		-8,618,417		-8,618,417	7
511,610	6,894,150	11,632,962		18,527,112	8
		672,229		672,229	9
75		5,036		5,036	10
		13,856		13,856	11
-28,937		-1,335,492		-1,335,492	12
		14,810,930		14,810,930	13
105,462		6,543,243		6,543,243	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
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.
		1,892		1,892	1
5,208		223,984		223,984	2
		11,324		11,324	3
40,522		2,360,042		2,360,042	4
108,892		5,113,941		5,113,941	5
		-1,424		-1,424	6
1,126,361	21,545,098	31,146,041		52,691,139	7
95,486		9,550,695		9,550,695	8
		8		8	9
-111,640		-5,796,051		-5,796,051	10
38,594		2,842,851		2,842,851	11
29,633		2,103,535		2,103,535	12
34,128		1,097,972		1,097,972	13
-299,753		-16,866,367		-16,866,367	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
-246		-8,124		-8,124	1
40,614		4,175,540		4,175,540	2
21,778		1,854,869		1,854,869	3
172,551		10,685,731		10,685,731	4
-7		-434		-434	5
13		-15,606		-15,606	6
26,592		1,792,847		1,792,847	7
4,274		186,233		186,233	8
8,559		333,162		333,162	9
-821		-47,255		-47,255	10
619		120,156		120,156	11
-7,762		-332,199		-332,199	12
55,037		3,417,746		3,417,746	13
12,798	578,961	279,326		858,287	14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

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Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
478		25,969		25,969	1
4,395		174,232		174,232	2
		-11,720,962		-11,720,962	3
-64,386		-1,949,135		-1,949,135	4
-3,411		-157,928		-157,928	5
1,980		81,030		81,030	6
-248,826	37,256	-8,354,785		-8,317,529	7
176,136		9,898,916		9,898,916	8
-17,189		-563,171		-563,171	9
67,475		5,411,793		5,411,793	10
130,147	828,387	5,038,074		5,866,461	11
		-3,188,169		-3,188,169	12
					13
					14
0	0	0	0	0	
6,397,937	30,785,441	295,218,916	943,759	326,948,116	
6,397,937	**30,785,441**	**295,218,916**	**943,759**	**326,948,116**	

Schedule Page: 310 Line No.: 1 Column: a

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

Schedule Page: 310 Line No.: 2 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.: 3 Column: c

Note 1: FERC Electric Tariff, Second Substitute Volume No. 5.

Schedule Page: 310.1 Line No.: 2 Column: j

Carolina Power and Light transmission service charges from a grandfathered agreement. Activity reflects both the base rate and Ancillary 1 base dollars.

Schedule Page: 310.8 Line No.: 12 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

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 2010/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	8,122,247	8,148,995
5	(501) Fuel	367,086,593	268,128,076
6	(502) Steam Expenses	28,907,113	27,462,158
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,208,809	2,292,093
10	(506) Miscellaneous Steam Power Expenses	27,491,410	26,084,645
11	(507) Rents	-16,811	-139
12	(509) Allowances	5,727,736	7,413,973
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	439,527,097	339,529,801
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,327,198	2,430,209
16	(511) Maintenance of Structures	3,066,982	3,373,971
17	(512) Maintenance of Boiler Plant	44,791,005	51,693,575
18	(513) Maintenance of Electric Plant	7,662,253	10,720,148
19	(514) Maintenance of Miscellaneous Steam Plant	1,905,454	2,680,460
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	59,752,892	70,898,363
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	499,279,989	410,428,164
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)		

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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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	170,994	149,905
63	(547) Fuel	2,928,243	1,120,722
64	(548) Generation Expenses	159,888	130,583
65	(549) Miscellaneous Other Power Generation Expenses	695,383	664,797
66	(550) Rents	39,362	32,341
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,993,870	2,098,348
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	192,230	70,016
70	(552) Maintenance of Structures	12,923	3,796
71	(553) Maintenance of Generating and Electric Plant	639,938	689,048
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	151,328	160,655
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	996,419	923,515
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	4,990,289	3,021,863
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	589,987,712	533,837,229
77	(556) System Control and Load Dispatching	813,631	932,635
78	(557) Other Expenses	9,086,718	7,633,702
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	599,888,061	542,403,566
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,104,158,339	955,853,593
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,026,341	1,004,962
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	21,190	16,786
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,208,411	1,300,071
87	(561.3) Load Dispatch-Transmission Service and Scheduling	28	2,571
88	(561.4) Scheduling, System Control and Dispatch Services	3,297,579	2,853,695
89	(561.5) Reliability, Planning and Standards Development	288,093	111,146
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	803,012	535,808
93	(562) Station Expenses	555,187	458,616
94	(563) Overhead Lines Expenses	3,269	10,965
95	(564) Underground Lines Expenses	524	510
96	(565) Transmission of Electricity by Others	50,412,116	53,542,955
97	(566) Miscellaneous Transmission Expenses	4,061,071	1,390,945
98	(567) Rents	210,165	36,524
99	TOTAL Operation (Enter Total of lines 83 thru 98)	61,886,986	61,265,554
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	43,490	69,420
102	(569) Maintenance of Structures	71,166	74,869
103	(569.1) Maintenance of Computer Hardware	55,136	67,689
104	(569.2) Maintenance of Computer Software	318,486	353,403
105	(569.3) Maintenance of Communication Equipment	248,068	284,000
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,085,353	2,102,622
108	(571) Maintenance of Overhead Lines	1,899,049	2,747,590
109	(572) Maintenance of Underground Lines	365,527	616,073
110	(573) Maintenance of Miscellaneous Transmission Plant		54
111	TOTAL Maintenance (Total of lines 101 thru 110)	5,086,275	6,315,720
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	66,973,261	67,581,274

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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	3,731,757	3,050,178
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,731,757	3,050,178
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)	3,731,757	3,050,178
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,522,753	6,256,386
135	(581) Load Dispatching	7,773	10,174
136	(582) Station Expenses	687,114	660,755
137	(583) Overhead Line Expenses	2,169,781	1,334,671
138	(584) Underground Line Expenses	2,763,095	2,637,965
139	(585) Street Lighting and Signal System Expenses	58,767	60,471
140	(586) Meter Expenses	773,524	1,438,274
141	(587) Customer Installations Expenses	203,759	212,309
142	(588) Miscellaneous Expenses	28,729,220	13,997,318
143	(589) Rents	3,337,497	2,094,128
144	TOTAL Operation (Enter Total of lines 134 thru 143)	44,253,283	28,702,451
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	294,457	487,690
147	(591) Maintenance of Structures	75,844	247,363
148	(592) Maintenance of Station Equipment	2,037,354	2,341,924
149	(593) Maintenance of Overhead Lines	32,047,547	35,161,388
150	(594) Maintenance of Underground Lines	2,353,820	3,224,876
151	(595) Maintenance of Line Transformers	326,879	432,107
152	(596) Maintenance of Street Lighting and Signal Systems	105,514	156,830
153	(597) Maintenance of Meters	151,929	173,504
154	(598) Maintenance of Miscellaneous Distribution Plant	1,218,930	1,352,158
155	TOTAL Maintenance (Total of lines 146 thru 154)	38,612,274	43,577,840
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	82,865,557	72,280,291
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,174,677	1,201,339
160	(902) Meter Reading Expenses	3,685,022	4,220,027
161	(903) Customer Records and Collection Expenses	23,650,268	23,995,865
162	(904) Uncollectible Accounts	34,192,516	21,443,093
163	(905) Miscellaneous Customer Accounts Expenses	64,641	38,965
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	62,767,124	50,899,289

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	2,366,813	1,506,578
168	(908) Customer Assistance Expenses	26,680,261	292,543
169	(909) Informational and Instructional Expenses	699,045	711,861
170	(910) Miscellaneous Customer Service and Informational Expenses	88	2,915
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	29,746,207	2,513,897
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	199,549	
175	(912) Demonstrating and Selling Expenses	4,401	9,879
176	(913) Advertising Expenses		206
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	203,950	10,085
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	20,956,051	16,502,049
182	(921) Office Supplies and Expenses	4,006,445	3,432,900
183	(Less) (922) Administrative Expenses Transferred-Credit	2,551,430	2,388,983
184	(923) Outside Services Employed	16,432,396	13,561,064
185	(924) Property Insurance	2,509,274	3,010,064
186	(925) Injuries and Damages	3,538,231	3,732,154
187	(926) Employee Pensions and Benefits	17,838,776	21,317,346
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	292,655	113,326
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,935,287	1,273,244
192	(930.2) Miscellaneous General Expenses	1,356,406	1,352,127
193	(931) Rents	2,494,546	2,833,394
194	TOTAL Operation (Enter Total of lines 181 thru 193)	68,808,637	64,738,685
195	Maintenance		
196	(935) Maintenance of General Plant	3,940,842	4,725,579
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	72,749,479	69,464,264
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,423,195,674	1,221,652,871

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.

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP Generating	RQ	AEG 3			
2	AEP Service Corporation	OS	20			
3	AEP Service Corporation	OS	30			
4	ALLETE, Inc. dba Minnesota Pwr	OS				
5	Ameren Energy Marketing	OS				
6	Associated Elect Cooperative	OS				
7	Barclays Bank PLC	OS				
8	Beech Ridge Energy LLC	OS				
9	Big Rivers Electric Corp	OS				
10	BP AMOCO	OS				
11	Buckeye Rural Electric Admin	OS				
12	Carolina Power & Light	OS				
13	Citigroup Energy Inc.	OS				
14	Conectiv Energy Supply 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 2010/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	Constellation Engy Commodities	OS				
2	Cook Inlet Energy Supply LP	OS				
3	DTE Energy Trading Inc.	OS				
4	Duke Energy Carolinas, LLC	OS				
5	Duke Power Company	OS				
6	Dynegy Power Marketing Inc.	OS				
7	EDF Trading North America LLC	OS				
8	Edison Mission Mktg & Trading	OS				
9	Endure Energy, LLC	OS				
10	Entergy Power Serv	OS				
11	Exelon Generation - Power Team	OS				
12	FirstEnergy Trading Services	OS				
13	Fowler Ridge II Wind Farm LLC	OS				
14	Hoosier Power Market	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 2010/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.

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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	Integrys Energy Services, Inc	OS				
2	J ARON & Company	OS				
3	JP Morgan Ventures Energy Corp	OS				
4	Kansas City Power & Light Co	OS				
5	LG&E Utilities Power Sales	OS				
6	Madison Gas and Electric Co	OS				
7	Midwest ISO	OS				
8	Mizuho Securities USA Inc	OS				
9	National Power Cooperative Inc	OS				
10	NC Electric Membership Corp.	OS				
11	NextEra Energy Power Mktg LLC	OS				
12	No Carolina Muni Pwr Agency #1	OS				
13	NRG Power Marketing Inc.	OS				
14	Ohio Economic Development Rider	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Old Dominion Elec.	OS				
2	OVEC Power Scheduling	OS				
3	PJM Interconnection	OS				
4	PP&L Energy Plus Co.	OS				
5	PSEG Energy Resources & Trade	OS				
6	Sempra Energy Solutions, LLC	OS				
7	Sempra Energy Trading	OS				
8	South Carolina Electric & Gas	OS				
9	Southeastern Pub Serv Auth -VA	OS				
10	Southen Maryland Elec Coop Inc	OS				
11	Southern Company	OS				
12	Southern Illinois Power Co-Op	OS				
13	The Energy Authority	OS				
14	Titlon Energy, LLC	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 2010/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:

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

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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	Town of Front Royal	OS				
2	TVA Bulk Power Trading	OS				
3	UBS Securities LLC	OS				
4	Union Electric Company	OS				
5	Wabash Valley Power Assn Inc.	OS				
6	Westar Energy Inc.	OS				
7	Wisconsin Electric Power Co	OS				
8	Wyandot Solar LLC	OS				
9	Adjustment	OS				
10						
11						
12						
13						
14						
	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 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,547,862			60,734,136	53,066,404		113,800,540	1
11,749				458,157		458,157	2
10,732,648			19,380,410	275,458,228		294,838,638	3
			50,798	64,527		115,325	4
			1,466	1,779		3,245	5
5,122				166,620		166,620	6
				1,617		1,617	7
				-5,230		-5,230	8
642				23,548		23,548	9
				4,916		4,916	10
16				370,433		370,433	11
403				11,853		11,853	12
				-676		-676	13
			39,383			39,383	14
15,631,380			104,443,543	485,544,169		589,987,712	

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 2010/Q4

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.
38,224			2,185,950	2,043,719		4,229,669	1
				1,922		1,922	2
1,640				115,248		115,248	3
73				3,980		3,980	4
85				4,770		4,770	5
			92,201	-2		92,199	6
			92,063	604		92,667	7
3,376				83,835		83,835	8
				8,709		8,709	9
2,846				106,856		106,856	10
51,877			42,596	1,919,699		1,962,295	11
				2,270		2,270	12
131,780				10,080,727		10,080,727	13
				6		6	14
15,631,380			104,443,543	485,544,169		589,987,712	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,864				93,380		93,380	1
43,517				1,829,618		1,829,618	2
3,325			5,588	227,867		233,455	3
2,323				69,697		69,697	4
7,791				323,940		323,940	5
			19,940			19,940	6
415,571			303	16,925,378		16,925,681	7
				210,576		210,576	8
10,007			47,586	799,615		847,201	9
83				2,198		2,198	10
			42,208	111		42,319	11
121				6,697		6,697	12
41				1,593		1,593	13
				7,485,164		7,485,164	14
15,631,380			104,443,543	485,544,169		589,987,712	

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)	
14,425				572,209		572,209	1
757,709			13,228,114	20,296,195		33,524,309	2
1,172,916			7,907,198	59,548,107		67,455,305	3
179,117				8,898,619		8,898,619	4
471,367				23,990,770		23,990,770	5
				3,397		3,397	6
360				13,448		13,448	7
240				14,975		14,975	8
7,724				262,643		262,643	9
							10
235				12,594		12,594	11
				1		1	12
3,271				163,045		163,045	13
			19,659			19,659	14
15,631,380			104,443,543	485,544,169		589,987,712	

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 2010/Q4

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.
			224,581			224,581	1
6,220				283,959		283,959	2
				2,248,483		2,248,483	3
			19,559	6,975		26,534	4
			211,508	-1,186		210,322	5
				7,272		7,272	6
			98,296			98,296	7
4,810				440,479		440,479	8
				-3,188,169		-3,188,169	9
							10
							11
							12
							13
							14
15,631,380			104,443,543	485,544,169		589,987,712	

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

Associated Company.

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

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

Schedule Page: 326 Line No.: 3 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: 326.4 Line No.: 9 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PJM Network Integ Trans Rev	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Network Integ Rev - Affil	Various	Various	FNS
5	PJM Point to Point Trans Service	Various	Various	LFP
6	PJM Trans Owner Admin Revenue	Various	Various	OLF
7	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
8	PJM Expansion Costs Recovery	Various	Various	OS
9	PJM Trans Distribution & Metering	Various	Various	OS
10	Grndfthrd Ancillary Rev - Affil	Various	Various	OS
11	Grndfthrd Base Rev - Affil	Various	Various	OS
12	RTO Formation Cost Recovery	Various	Various	OS
13	SECA Transmission Rev	Various	Various	OS
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 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PJMOATT	Various	Various				1
PJMOATT	Various	Various				2
PJMOATT	Various	Various				3
PJMOATT	Various	Various				4
PJMOATT	Various	Various				5
PJMOATT	Various	Various				6
PJMOATT	Various	Various				7
PJMOATT	Various	Various				8
PJMOATT	Various	Various				9
PJMOATT	Various	Various				10
PJMOATT	Various	Various				11
PJMOATT	Various	Various				12
PJMOATT	Various	Various				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 Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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 (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
396,867			396,867	1
10,733,198			10,733,198	2
45,338			45,338	3
89			89	4
2,434,084			2,434,084	5
	486,937		486,937	6
	13,349		13,349	7
111,451			111,451	8
		573,632	573,632	9
		109,351	109,351	10
3,775			3,775	11
3,336			3,336	12
		410,884	410,884	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
13,728,138	**500,286**	**1,093,867**	**15,322,291**	

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 for the total revenue by the major classes listed.

Schedule Page: 328 Line No.: 9 Column: m

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

Schedule Page: 328 Line No.: 10 Column: m

AEP's OATT FERC Electric Tariff First Revised Volume No. 5.

Schedule Page: 328 Line No.: 13 Column: m

See "Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund" in Footnote #2 Rate Matters Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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 Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	AEP Service Corporation	FNS					42,515,889	42,515,889
2	PJM-Enhancements	OS					5,224,631	5,224,631
3	PJM-TO	OS					86,725	86,725
4	PJM-NITS	OS					2,435,313	2,435,313
5	GFA Trans Exp	OS					149,558	149,558
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						50,412,116	50,412,116

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

Affiliated Company

AEP Transmission Equalization Agreement - Modified Effective Nov 2010

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

Modified AEP Transmission Agreement (TA) - Effective Nov 2010

In June 2009, AEPSC, on behalf of the parties in 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 generally on the basis of the TA parties' 12-month coincident peark and reimburse transmission revenues based on individual cost of service instead of the MLR method. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010.

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

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

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

Transmission Owner Charges and Credits (PJM OATT Tariff Sixth Revised Volume No. 1).

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

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

Schedule Page: 332 Line No.: 5 Column: a

Grandfathered Agreements - GFA (AEP's OATT FERC Electric Tafiff First Revised Volume No. 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 2010/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	281,049
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	41,162
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	94,391
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Affiliated Billings (net)	-17,179
7	Associated Business Development	561,983
8	Utility Corporate Borrowing Program Shared Costs	146,639
9	Corporate Contributions and Membership	182,766
10	Chambers of Commerce	100,331
11	Ohio Manufactureer Seminar	5,000
12	Clearing of Unclaimed funds (business to business)	-22,930
13	Clearing of retention items	-19,136
14	Various items <$5,000	2,330
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	1,356,406

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 2010/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			9,641,291		9,641,291
2	Steam Production Plant	46,596,737	4,337,300			50,934,037
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,078,943				9,078,943
7	Transmission Plant	13,952,264				13,952,264
8	Distribution Plant	61,613,392				61,613,392
9	Regional Transmission and Market Operation					
10	General Plant	3,452,694		3,460		3,456,154
11	Common Plant-Electric					
12	TOTAL	134,694,030	4,337,300	9,644,751		148,676,081

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.

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Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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	46,612					
14	311.15	210,185					
15	312	486,895					
16	312.15	1,054,446					
17	314	117,250					
18	314.15	191,445					
19	315	40,440					
20	315.15	107,609					
21	316	18,115					
22	316.15	23,480					
23	TOTAL STEAM	2,296,477					
24							
25	OTHER GENERATION						
26	341	13,904					
27	342	7,545					
28	344	323,906					
29	345	45,934					
30	346	8,443					
31	TOTAL OTHER	399,732					
32							
33	TRANSMISSION						
34	352	48,015					
35	352.15	397					
36	353	313,846					
37	353.15	19,669					
38	354	17,110					
39	354.15	17,940					
40	355	85,533					
41	355.15	3,174					
42	356	67,185					
43	356.15	13,833					
44	357	10,498					
45	358	18,883					
46	TOTAL TRANSMISSION	616,083					
47							
48	DISTRIBUTION						
49	361	9,781					
50	362	238,551					

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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	232,686					
13	365	242,679					
14	366	95,957					
15	367	375,087					
16	368	305,488					
17	369	137,366					
18	370	74,189					
19	370.16	8,102					
20	371	25,268					
21	372	103					
22	373	12,399					
23	TOTAL DISTRIBUTION	1,757,656					
24							
25	GENERAL PLANT						
26	390	54,999					
27	391	4,794					
28	391.15	480					
29	393	302					
30	394	10,608					
31	395	632					
32	397	12,512					
33	397.15	21					
34	397.16	2,126					
35	398	1,588					
36	TOTAL GENERAL	88,062					
37	DEPRECIABLE SUM	5,158,010					
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336.1 Line No.: 37 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 11/30/2010

(3) Depreciation for 2010 was computed monthly by application of rates to prior month ending balances

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 2010/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 for long-term forcasts.	118,347		118,347	
3					
4	AEP Ohio Electric Security Plan				
5	PUCO Case No. 11-346-EL-SSO		76,594	76,594	
6					
7	Ohio CSP/OPCO Merger Filing				
8	FERC Docket No. EC11-37-000				
9	PUCO Case No. 10-2376-EL-UNC		40,864	40,864	
10					
11	Ohio Significant Excessive Earnings Test				
12	PUCO Case No. 10-1261-EL-UNC		15,617	15,617	
13					
14	AEP Ohio Distribution Case		29,092	29,092	
15	PUCO Case No. 11-351-EL-AIR				
16					
17	Miscellaneous Items		12,141	12,141	
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	118,347	174,308	292,655	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	118,347					2
							3
							4
Electric	928	76,594					5
							6
							7
							8
Electric	928	40,864					9
							10
							11
Electric	928	15,617					12
							13
Electric	928	29,092					14
							15
							16
Electric	928	12,141					17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
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							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		292,655					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 2010/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	2 items < $50,000
7		
8	A(2) Transmission	5 items < $50,000
9		
10	A2(a) Transmission: Overhead	1 item < $50,000
11		
12	A(3) Distribution	4 items < $50,000
13		
14	A(4) Regional Transmission and Mkt Operation	2 item < $50,000
15		
16	A(5) Environment: (Other Than Equipme	Clean Power Initiative
17		4 items < $50,000
18		
19	A(6) Other:	10 Items < $50,000
20		
21		
22	A(7) TOTAL COST INCURRED INTERNALLY	
23		
24	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
25	DEMONSTRATION PERFORMED EXTERNALLY	
26		
27	B(1) Research Support to Elec. Research	EPRI Environmental Controls
28	Council & Elec. Power Research Inst	EPRI Environmental Science
29		EPRI Research Portfolio
30		56 items < $50,000
31		
32		
33	B(4) Research Support to Others	10 items < $50,000
34		
35	B(5) TOTAL COSTS INCURRED EXTERNALLY	
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 2010/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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
50,192		506	50,192		4
					5
47,467		588	47,467		6
					7
17,467		566	17,467		8
					9
2,335		566	2,335		10
					11
25,058		566, 588	25,058		12
					13
892		588	892		14
					15
63,824		506	63,824		16
43,981		506	43,981		17
					18
97,682		Various	97,682		19
					20
					21
348,898			348,898		22
					23
					24
					25
					26
52,095		506	52,095		27
184,510		506	184,510		28
228,665		Various	228,665		29
327,183		Various	327,183		30
					31
					32
51,614		Various	51,614		33
					34
844,067			844,067		35
					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 2010/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	17,564,767		
4	Transmission	2,401,398		
5	Regional Market			
6	Distribution	23,203,793		
7	Customer Accounts	5,106,908		
8	Customer Service and Informational	524,513		
9	Sales			
10	Administrative and General	-559,112		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	48,242,267		
12	Maintenance			
13	Production	9,295,303		
14	Transmission	826,259		
15	Regional Market			
16	Distribution	9,783,362		
17	Administrative and General	1,155,028		
18	TOTAL Maintenance (Total of lines 13 thru 17)	21,059,952		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,860,070		
21	Transmission (Enter Total of lines 4 and 14)	3,227,657		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	32,987,155		
24	Customer Accounts (Transcribe from line 7)	5,106,908		
25	Customer Service and Informational (Transcribe from line 8)	524,513		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	595,916		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	69,302,219	3,036,464	72,338,683
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			

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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)	69,302,219	3,036,464	72,338,683
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	19,630,977	860,128	20,491,105
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	19,630,977	860,128	20,491,105
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,565,084	200,018	4,765,102
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,565,084	200,018	4,765,102
77	Other Accounts (Specify, provide details in footnote):			
78	151 - Fuel Stock	5		5
79	152 - Fuel Stock Undistributed	2,086,182		2,086,182
80	163 - Stores Expense Undistributed	2,142,881	-2,142,881	
81	182 - Other Regulatory Assets	264,325	-264,325	
82	184 - Clearing Accounts	1,689,404	-1,689,404	
83	185 - ODD Temporary Facilities	54,771		54,771
84	186 - Misc Deferred Debits	159,913		159,913
85	188 - Research & Development	-1,195		-1,195
86	242 - Misc Current & Accrued Liab	234		234
87	421 - Misc Nonoperating Income	14,117		14,117
88	426 - Political Activities	5,025		5,025
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,415,662	-4,096,610	2,319,052
96	TOTAL SALARIES AND WAGES	99,913,942		99,913,942

Schedule Page: 354 Line No.: 96 Column: b

Amounts include salaries and wages associated with AEP's 2010 Cost Reduction Initiative. See Notes to the Financial Statements (pages 122-123) for additional details.

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Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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 Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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)				29,550,163
3	Net Sales (Account 447)				(7,992,168)
4	Transmission Rights				(10,899,580)
5	Ancillary Services				1,481,511
6	Other Items (list separately)				
7	Congestion				8,033,440
8	Operating Reserves				918,003
9	Transmission Purchase Expense				(19,530)
10	Transmission Losses				4,728,591
11	Meter Corrections				(118,281)
12	Inadvertent				(54,175)
13	Capacity Credits				(10,775,058)
14	Miscellaneous				(531,895)
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
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41					
42					
43					
44					
45					
46	TOTAL				14,321,021

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Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year: Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year: Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		N/A		335,532	.0866/MWH	29,070
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)				335,532		29,070

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

Represents the number of units of ancillary service.

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

Represents the Company's MLR share of AEP System revenues, Column G, divided by Column E.

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 2010/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

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

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 2010/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 2010/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	11,261,918
4	Nuclear	
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	1,259,229
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	12,521,147
10	Purchases	15,631,380
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)	28,152,527

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	21,235,052
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,397,937
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	519,538
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	28,152,527

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,648,221	618,954	3,383	5	1900
30	February	2,322,234	509,838	3,307	8	0800
31	March	2,122,747	412,078	3,056	2	2000
32	April	1,936,350	425,983	2,689	6	1500
33	May	2,054,394	347,330	3,689	27	1600
34	June	2,738,446	772,897	4,205	23	1500
35	July	3,293,921	1,123,682	4,364	23	1600
36	August	3,025,204	915,525	4,222	12	1600
37	September	2,140,522	468,660	4,168	2	1600
38	October	1,754,945	268,277	2,823	11	1500
39	November	1,797,026	273,079	2,864	24	1800
40	December	2,318,517	462,849	3,546	13	1900
41	TOTAL	28,152,527	6,599,152			

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 2010/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)	948			100		
7	Plant Hours Connected to Load	7876			1389		
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	322			16		
12	Net Generation, Exclusive of Plant Use - KWh	4025664000			65072000		
13	Cost of Plant: Land and Land Rights	236497			125244		
14	Structures and Improvements	40065647			6667669		
15	Equipment Costs	642704725			37150814		
16	Asset Retirement Costs	34346041			6247988		
17	Total Cost	717352910			50191715		
18	Cost per KW of Installed Capacity (line 17/5) Including	670.4233			472.3926		
19	Production Expenses: Oper, Supv, & Engr	1717535			802368		
20	Fuel	114007740			3279065		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	13542024			531894		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1118970			293174		
26	Misc Steam (or Nuclear) Power Expenses	8975236			926013		
27	Rents	0			0		
28	Allowances	2066545			275110		
29	Maintenance Supervision and Engineering	411387			30381		
30	Maintenance of Structures	734301			193126		
31	Maintenance of Boiler (or reactor) Plant	17703256			825818		
32	Maintenance of Electric Plant	2491494			89526		
33	Maintenance of Misc Steam (or Nuclear) Plant	574227			47108		
34	Total Production Expenses	163342715			7293583		
35	Expenses per Net KWh	0.0406			0.1121		
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	1928898	10517	0	36965	1382	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11452	136875	0	11478	137107	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	53.915	94.925	0.000	0.000	90.340	0.000
41	Average Cost of Fuel per Unit Burned	53.982	92.239	0.000	76.544	89.199	0.000
42	Average Cost of Fuel Burned per Million BTU	2.357	16.045	0.000	3.334	15.490	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.043	0.000	0.000
44	Average BTU per KWh Net Generation	10990.000	0.000	0.000	13187.000	0.000	0.000

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/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)	579			601		
7	Plant Hours Connected to Load	6901			7918		
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	244388000			3462349000		
13	Cost of Plant: Land and Land Rights	175499			676940		
14	Structures and Improvements	1332302			23858972		
15	Equipment Costs	17345480			481707987		
16	Asset Retirement Costs	225419			1050643		
17	Total Cost	19078700			507294542		
18	Cost per KW of Installed Capacity (line 17/5) Including	331.2274			799.3800		
19	Production Expenses: Oper, Supv, & Engr	190088			1805717		
20	Fuel	8532755			88216323		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	182598			4227763		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1751			393800		
26	Misc Steam (or Nuclear) Power Expenses	282409			3451838		
27	Rents	0			-16811		
28	Allowances	685343			673669		
29	Maintenance Supervision and Engineering	201750			539079		
30	Maintenance of Structures	65616			818630		
31	Maintenance of Boiler (or reactor) Plant	373718			13673287		
32	Maintenance of Electric Plant	184864			2644634		
33	Maintenance of Misc Steam (or Nuclear) Plant	59681			0		
34	Total Production Expenses	10760573			116427929		
35	Expenses per Net KWh	0.0440			0.0336		
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	106264	891	0	1549798	19664	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12052	145547	0	11253	137606	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	53.959	92.539	0.000	56.141	100.947	0.000
41	Average Cost of Fuel per Unit Burned	53.868	86.025	0.000	55.519	99.402	0.000
42	Average Cost of Fuel Burned per Million BTU	2.235	14.073	0.000	2.467	17.199	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	10479.000	0.000	0.000	9933.000	0.000	0.000

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 2010/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0.0000			0.0000
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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
		785			379			340	6
		4449			4449			7849	7
		0			0			0	8
		780			337			333	9
		780			337			330	10
		0			0			0	11
		2434596000			1002200000			2462245000	12
		74828			32550			5959406	13
		36796129			16006316			169451269	14
		658901816			286622290			596507887	15
		997665			433984			396956	16
		696770438			303095140			772315518	17
		828.0100			828.0157			2132.8202	18
		0			647968			714759	19
		0			33414325			53808125	20
		0			0			0	21
		0			3203830			7170599	22
		0			0			0	23
		0			0			0	24
		0			49682			351430	25
		0			2167149			1278082	26
		0			0			0	27
		0			706971			1027500	28
		0			127770			779218	29
		0			146868			1069957	30
		0			4769345			4246107	31
		0			1101604			513650	32
		0			493502			730936	33
		0			46829014			71690363	34
		0.0000			0.0467			0.0291	35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
1132843	14204	0	469452	6179	0	1016543	18294	0	38
11585	136768	0	11585	136768	0	11923	137609	0	39
68.905	96.809	0.000	69.013	96.808	0.000	47.635	95.729	0.000	40
65.350	92.829	0.000	65.265	92.829	0.000	47.420	89.855	0.000	41
2.820	16.160	0.000	2.817	16.160	0.000	1.989	15.547	0.000	42
0.030	0.000	0.000	0.031	0.000	0.000	0.020	0.000	0.000	43
10815.000	0.000	0.000	10889.000	0.000	0.000	9889.000	0.000	0.000	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 2010/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
886			438			0			6
2533			122			0			7
0			0			0			8
840			507			0			9
810			438			0			10
22			0			0			11
1221136000			38093000			0			12
3000000			713584			0			13
10574793			3329543			0			14
199277506			186550499			0			15
0			0			0			16
212852299			190593626			0			17
232.1181			293.2210			0.0000			18
1429972			813839			0			19
42099466			500177			0			20
0			0			0			21
42480			5925			0			22
0			0			0			23
0			0			0			24
0			0			0			25
7556982			2853702			0			26
0			0			0			27
177513			115084			0			28
164994			72618			0			29
-39			38524			0			30
3180571			18903			0			31
531188			105292			0			32
0			0			0			33
55183127			4524064			0			34
0.0452			0.1188			0.0000			35
Gas			Gas						36
MCFs			MCFs						37
8948401	0	0	468794	0	0	0	0	0	38
1014000	0	0	1061000	0	0	0	0	0	39
4.606	0.000	0.000	6.036	0.000	0.000	0.000	0.000	0.000	40
4.604	0.000	0.000	6.036	0.000	0.000	0.000	0.000	0.000	41
4.540	0.000	0.000	5.689	0.000	0.000	0.000	0.000	0.000	42
0.034	0.000	0.000	0.074	0.000	0.000	0.000	0.000	0.000	43
7431.000	0.000	0.000	13057.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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

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 expneses totalling $23,228,616 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 2010/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

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 2010/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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 2010/Q4

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

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

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
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			30
			31
			32
			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/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						
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11						
12						
13						
14						
15						
16						
17						
18						
19						
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44						
45						
46						

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
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						34
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						38
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						40
						41
						42
						43
						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 2010/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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

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 Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	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

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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

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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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	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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	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								
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25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
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 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								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	4,631,876	4,702,049					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	1,297,075	9,799,461	11,096,536					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	375,612	443,930					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	744,026	1,144,403					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
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

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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	1,445,792	1,708,228					8
2-954 ACSR	292,501	1,255,302	1,547,803					9
		132,751	132,751					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	1,566,059	1,927,003					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
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

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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	398,878	424,444					17
556.5 ACSR 18/1								18
336.4 ACSR								19
636 ACSR	156,176	1,351,501	1,507,677					20
636 ACSR								21
636 ACSR	289,360	1,781,791	2,071,151					22
600 CU PIPT		745,349	745,349					23
600 CU PIPT	2	637,129	637,131					24
636 ACSR								25
636 ACSR	51,703	526,935	578,638					26
636 AA	636,315	1,682,366	2,318,682					27
636 ACSR	692,511	1,341,497	2,034,008					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	1,510,052	1,729,347					32
336.4 ACSR								33
636 ACSR	376,920	2,287,430	2,664,350					34
336.4 ACSR								35
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
636 ACSR	23,380	719,514	742,894					1
636 ACSR								2
636 ACSR	665,085	1,213,440	1,878,525					3
636 ACSR								4
636 ACSR								5
636 ACSR	1,226,980	4,325,900	5,552,880					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	1,207,434	1,225,716					32
1272 ACSR	776,375	2,479,633	3,256,008					33
1272 ACSR								34
1272 ACSR								35
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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	611,269	721,792					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	1,391,462	1,490,032					25
636 AA								26
1259 CU PIPT		818,625	818,625					27
1272 KCM								28
636 ACSR	226,914	1,016,901	1,243,815					29
636 ACSR	420,061	4,408,831	4,828,892					30
336.4 ACSR								31
336.4 ACSR	212,689	1,914,077	2,126,766					32
636 ACSR								33
636 ACSR								34
336 ACSR	137,673	257,199	394,872					35
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

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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	2,210,884	2,385,752					9
636 ACSR	531,105	5,016,127	5,547,232					10
636 ACSR								11
636 ACSR								12
636 ACSR	30,427	912,264	942,691					13
954 ACSR	259,762	1,235,603	1,495,365					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	62,758	1,026,938	1,089,696					24
636 ACSR								25
636 ACSR								26
336 ACSR	35,117	1,300,492	1,335,609					27
983.1 ACSR	268,205	274,143	542,348					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
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	36

TRANSMISSION LINE STATISTICS (Continued)

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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	953,148	1,448,652					7
	6,722,441	48,972,400	55,694,841					8
								9
				1,399	835,162		836,561	10
				1,389	829,487		830,876	11
				1,005	599,927		600,932	12
								13
								14
								15
								16
								17
								18
								19
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								30
								31
								32
								33
								34
								35
	37,424,704	229,859,264	267,283,963	3,793	2,264,576		2,268,369	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%

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 2010/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	None						
3							
4	Lines Altered:						
5	None						
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
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39							
40							
41							
42							
43							
44	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 2010/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
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
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									34
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									42
									43
									44

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	137.50	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					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BIXBY-OH	T	345.00	138.00	35.00
2		T	345.00	138.00	34.50
3		T	138.00	70.50	13.09
4		T	138.00	13.80	
5		T	138.00	13.80	13.80
6		T	138.00	13.09	
7		T	69.00	13.80	
8		T	69.00	13.20	
9		T	69.00	13.09	
10		T	69.00	4.36	
11		T	40.00	14.50	
12		T	40.00	13.80	
13		T	34.50	4.00	
14		T	23.00	13.09	
15		T	13.20	4.00	
16		T	13.20		
17	BLACKLICK-OH	D	138.00	35.40	13.80
18		D	34.50		
19		D	13.80		
20	BLENDON-OH	D	138.00	35.40	13.80
21		D	138.00	34.50	13.80
22	BRIGGSDALE-OH	D	40.00	13.80	
23		D	13.80		
24	BROOKSIDE (CS)-OH	D	138.00	13.80	
25		D	138.00	13.09	
26	BUCKSKIN-OH	D	69.00	12.00	
27	CAMP SHERMAN-OH	D	69.00	13.20	
28		D	69.00	13.09	
29	CANAL STREET-OH	D	138.00	13.80	13.80
30		D	13.80		
31		D	13.20		
32	CENTERBURG-OH	D	138.00	35.40	13.80
33	CIRCLEVILLE-OH	T	138.00	69.00	13.20
34		T	138.00	69.00	13.20
35		T	138.00	13.20	
36		T	138.00		
37		T	69.00		
38		T	13.20		
39					
40					

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CLARK STREET-OH	D	69.00		
2		D	69.00	12.00	
3		D	69.00		
4	CLINTON-OH	D	138.00	13.80	13.80
5	COLUMBIA(CS)-OH	D	40.00	13.20	
6	CONESVILLE PLANT-OH	T	345.00	138.00	34.50
7		T	138.00	70.73	13.20
8		T	138.00		
9	COOLVILLE (CS)-OH	D	69.00	13.20	
10		D	69.00	13.09	
11		D	13.20		
12	COPELAND-OH	D	69.00	13.20	
13		D	13.20		
14	CORNER-OH	D	138.00	13.09	
15	CORRIDOR-OH	T	345.00	138.00	34.50
16		T	345.00	138.00	13.80
17		T	138.00	34.50	13.80
18		T	138.00		
19	CORWIN-OH	D	138.00	13.09	
20	DAVIDSON (CS)-OH	D	138.00	13.80	
21		D	13.80		
22	DAVON-OH	D	69.00	13.20	
23	DELANO-OH	D	138.00	69.00	13.20
24	DELAWARE (CSP)-OH	T	138.00	69.00	13.09
25		T	138.00	40.00	13.80
26		T	138.00	35.40	13.80
27		T	138.00	34.50	13.80
28		T	138.00	13.80	
29		T	138.00		
30		T	34.50		
31		T	13.20		
32	DUBLIN(CS)-OH	D	138.00	13.80	
33		D	13.80		
34	DUCK CREEK-OH	D	138.00	13.09	
35		D	23.00	13.09	
36	EAST BROAD STREET-OH	T	138.00	40.00	13.80
37		T	138.00		
38		T	40.00		
39		T	13.80	39.40	13.80
40		T	13.20		

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 2010/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.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ELK-OH	D	69.00	13.20	
2	ELLIOTT-OH	T	138.00	69.00	13.20
3	ETNA ROAD-OH	D	40.00	13.80	4.30
4		D	13.20		
5	FIFTH AVENUE-OH	D	138.00	39.40	13.80
6		D	13.80		
7	GAHANNA-OH	D	138.00	35.40	13.80
8		D	138.00	34.50	13.80
9		D	138.00	13.80	
10		D	13.20		
11	GALLOWAY ROAD-OH	D	69.00	13.80	
12		D	13.20		
13	GAY STREET-OH	D	138.00	13.80	13.80
14		D	13.80		
15	GENOA-OH	T	138.00	70.50	13.80
16		T	138.00	69.00	12.00
17		T	138.00	34.50	13.80
18		T	138.00		
19		T	69.00		
20	GROVES ROAD-OH	T	138.00	40.00	13.80
21		T	138.00	13.80	
22		T	138.00	13.80	13.80
23		T	138.00		
24		T	46.00		
25		T	40.00	13.80	
26		T	13.80		
27	HALL-OH	D	138.00	13.80	
28		D	13.80		
29	HANERS-OH	D	69.00	13.09	
30		D	13.20		
31	HARMAR-OH	D	23.00	4.36	
32	HARMAR HILL-OH	D	138.00	13.09	
33	HARRISON-OH	T	138.00	69.00	13.80
34	HESS STREET-OH	D	138.00	13.80	
35		D	138.00		
36		D	13.80		
37	HIGHLAND (CS)-OH	D	69.00	13.20	
38		D	69.00		
39		D	13.20		
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	137.50	13.80
10		T	138.00	35.40	13.80
11	IDAHO-OH	D	69.00	12.00	
12	JEFFERSON (CS)-OH	D	69.00	13.20	
13		D	13.20		
14	JUG STREET-OH	T	345.00	137.50	13.80
15		T	138.00	35.40	13.80
16	KARL ROAD-OH	D	138.00	13.80	13.80
17		D	13.80		
18		D	13.20		
19	KENNY-OH	D	138.00	13.80	13.80
20		D	13.20		
21	KIMBERLY-OH	D	138.00	13.09	
22	KIRK-OH	T	345.00	138.00	13.00
23		T	138.00	69.00	34.00
24		T	138.00	34.50	13.00
25		T	34.50		
26	LAYMAN-OH	D	138.00	13.09	
27	LAZELLE-OH	D	69.00	13.80	
28		D	13.20		
29	LEE-OH	D	69.00	12.00	
30		D	13.20		
31	LICK-OH	T	138.00	69.00	13.20
32		T	138.00		
33		T	69.00	13.00	
34		T	69.00		
35		T	34.50	12.00	
36		T	13.20		
37	LINCOLN STREET-OH	D	69.00	13.80	
38	LINWORTH-OH	D	138.00	40.00	13.80
39		D	138.00	13.80	
40		D	13.20		

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SUBSTATIONS

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1	LIVINGSTON AVENUE-OH	D	40.00	13.00	
2	MADISON (CS)-OH	D	69.00	13.80	
3		D	69.00		
4	MALISZEWSKI 138 KV-OH	T	138.00	35.40	13.80
5		T	138.00	34.50	13.80
6		T	34.50		
7	MALISZEWSKI 765 KV-OH	T	765.00	138.00	13.80
8	MARION ROAD-OH	T	138.00	40.00	13.00
9		T	138.00	39.40	13.80
10		T	138.00		
11		T	40.00	13.00	
12		T	13.80	13.80	
13		T	13.20		
14	MCCOMB (CS)-OH	T	138.00	39.40	13.80
15		T	138.00		
16		T	13.20		
17	MEIGS (CS)-OH	D	69.00	13.09	
18		D	69.00	13.00	
19		D	69.00		
20		D	13.20		
21	MIFFLIN-OH	D	138.00	13.80	
22		D	13.20		
23	MILL CREEK (CSP)-OH	D	138.00	24.80	
24		D	138.00	13.09	
25	MORSE ROAD-OH	D	138.00	13.80	13.80
26		D	138.00		
27		D	13.20		
28	MOUND STREET-OH	D	138.00	13.80	13.80
29		D	13.80		
30	OSU-OH	D	138.00	13.80	
31		D	13.80		
32	PARK-OH	D	69.00	13.80	
33		D	13.20		
34	PARSONS-OH	D	40.00	13.80	
35		D	13.80		
36	PEACH MOUNT-OH	D	34.50	12.00	
37		D	13.20	4.00	
38	POLARIS-OH	D	138.00	35.40	13.80
39		D	34.50		
40	PORTERFIELD-OH	D	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	POSTON-OH	T	138.00	69.00	13.40
2		T	138.00		
3		T	69.00	13.20	
4		T	69.00	13.09	
5		T	69.00	12.00	
6	RARDEN-OH	D	69.00	34.50	13.00
7	RAVEN-OH	D	69.00	13.20	
8	RENO-OH	D	138.00	13.09	
9	REYNOLDSBURG-OH	D	40.00	13.20	4.15
10		D	7.50		
11	RIO-OH	D	138.00	13.20	
12		D	13.20		
13	RIVERVIEW (CSP)-OH	D	138.00	13.80	
14		D	138.00		
15	ROBERTS-OH	T	345.00	138.00	34.50
16		T	345.00	137.50	13.80
17		T	138.00	13.80	
18		T	13.20		
19		T	13.20		
20	ROSS-OH	T	138.00	69.00	13.20
21		T	138.00	34.50	12.00
22		T	138.00		
23		T	69.00	13.00	
24		T	69.00		
25		T	13.20		
26	ROZELLE-OH	D	138.00	13.09	
27	SAINT CLAIR AVENUE (CS)-OH	D	138.00	40.00	13.00
28		D	138.00	13.80	13.80
29		D	138.00		
30	SARDINIA-OH	D	69.00	13.20	
31		D	13.20		
32	SAWMILL-OH	T	138.00	69.00	13.00
33		T	138.00	34.50	13.80
34		T	138.00	13.80	
35		T	138.00		
36	SCIOTO TRAIL (CS)-OH	D	138.00	13.20	7.24
37	SCIPPO-OH	D	138.00	13.09	
38					
39					
40					

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

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2010/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ZUBER-OH	D	138.00	13.80	
2		D	13.80		
3					
4	23 STATIONS UNDER 10 MVA	T/D			
5					
6					
7					
8	COMMONLY OWNED SUBSTATIONS				
9	#5 CORRIDOR/FRANKLIN CO, OH - NOTE A	UNATTENDED T	345.00		
10	#50 BECKJORD/NEW RICHMOND, OH - NOTE B	ATTENDED T	22.00	345.00	
11	#52 STUART/ADAMS CO, OH - NOTE A	SUPERVISORY			
12		CONTROL T	345.00	138.00	
13	SEE NOTE B	MONITOR T	22.00	345.00	
14	SEE NOTE A	MONITOR T	22.00	345.00	
15	SEE NOTE D	ATTENDED T	22.00	345.00	
16	SEE NOTE E	SUPERVISORY			
17		CONTROL T	345.00		
18	#52 PIERCE/CLERMONT CO, OH - NOTE B	ATTENDED T	345.00		
19	#50 GREENE/GAYTON, OH - NOTE B	SUPERVISORY			
20		CONTROL T	345.00		
21	#61 FOSTER/WARREN CO, OH - NOTE B	UNATTENDED T	345.00		
22	#62 ZIMMER/CLERMONT CO, OH - NOTES A & C	ATTENDED T	22.00	345.00	
23	#66 CONESVILLE/CONESVILLE OH - NOTE A	ATTENDED T	22.00	345.00	
24	#71 BIXBY/GROVEPORT, OH - NOTE A	UNATTENDED T	345.00		
25	#74 BEATTY RD/GROVECITY, OH - NOTES A & B	UNATTENDED T	345.00		
26	#241 TERMINAL/CINCINNATI, OH - NOTE C	ATTENDED T	345.00		
27	#243 PORT UNION/BUTLER CO, OH - NOTE C	ATTENDED T	345.00		
28	#245 DON MARQUIS/PIKE CO, OH - NOTE B	UNATTENDED T	345.00		
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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	1				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	5	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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
675	1					1
675	1					2
90		1				3
42	1	1				4
158	2					5
25		2				6
7		2				7
22		1				8
20	1	3				9
9		1				10
33		1				11
9		1				12
9		1				13
9		1				14
5		1				15
			STATCAP	2	6	16
50	1					17
			STATCAP	1	5	18
			STATCAP	1	4	19
100	2					20
25	1					21
42	2					22
			STATCAP	1	3	23
100	2					24
50		1				25
20	1					26
3	1					27
20	1					28
252	3					29
			STATCAP	4	22	30
			STATCAP	4	31	31
50	1					32
34		1				33
60	2					34
30	1					35
			STATCAP	1	48	36
			STATCAP	1	12	37
			STATCAP	3	10	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 2010/Q4

SUBSTATIONS (Continued)

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

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

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
75	1					2
63	3					3
			STATCAP	2	10	4
42	1					5
			STATCAP	1	3	6
50	1					7
53	2					8
50	1					9
			STATCAP	2	6	10
62	3					11
			STATCAP	3	10	12
252	3					13
			STATCAP	6	38	14
90	1					15
130	1					16
92	2					17
			STATCAP	2		18
			STATCAP	2		19
75	1					20
50	1					21
168	2	1				22
			STATCAP	1		23
			STATCAP	1	11	24
22		2				25
			STATCAP	5	20	26
92	2					27
			STATCAP	2	14	28
25	1					29
			STATCAP	1	4	30
11	2					31
20	1					32
56	1					33
167	4					34
			STATCAP	1	62	35
			STATCAP	2	13	36
45	2					37
			STATCAP	1	13	38
			STATCAP	2	5	39
						40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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
600	2					9
50	1					10
11	1					11
21	2					12
			STATCAP	1	3	13
450	1					14
50	1					15
251	3					16
			STATCAP	5	25	17
			STATCAP	1	4	18
168	2					19
			STATCAP	2	10	20
40	2					21
560	1					22
90	1					23
42	1					24
			STATCAP	1	4	25
20	1					26
45	2					27
			STATCAP	1	4	28
11	1					29
			STATCAP	1	3	30
90	3					31
			STATCAP	1	43	32
2		1				33
			STATCAP	1	18	34
5		1				35
			STATCAP	2	7	36
60	2					37
42	1					38
42	1					39
			STATCAP	2	7	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 2010/Q4

SUBSTATIONS (Continued)

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

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

SUBSTATIONS (Continued)

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

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

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

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

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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
			STATCAP	1	7	2
						3
150	27					4
						5
						6
						7
						8
						9
504	1					10
						11
250	1					12
1920	3					13
640	1					14
900		1				15
						16
						17
						18
						19
						20
						21
1955	2					22
910	1					23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.8 Line No.: 8 Column: a

SUBSTATION NOTES:
- For Commonly Owned substations as noted:
- Applies to page 426.8 lines 8 - 28

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 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%

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 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Audit Services	AEPSC	920	785,768
3	Business Logistics	AEPSC	923	1,617,828
4	Civil & Political Activities and Other Svcs	AEPSC	426	1,104,014
5	Construction Services	AEPSC	107, 108	34,248,596
6	Corporate Accounting	AEPSC	920	2,950,812
7	Corporate Communications	AEPSC	920	901,542
8	Corporate Planning & Budgeting	AEPSC	920	1,266,417
9	Customer Accounts Expenses - Operation	AEPSC	901-905	21,526,336
10	Customer and Distribution Services	AEPSC	920	730,767
11	Customer Service and Informational Expenses - Oper	AEPSC	907-910	4,124,125
12	Distribution Expenses - Maintenance	AEPSC	Various	383,858
13	Distribution Expenses - Operation	AEPSC	Various	5,900,394
14	Environment & Safety	AEPSC	920	1,313,888
15	Fuel and Storeroom Services	AEPSC	151, 152, 163	2,606,441
16	Human Resources	AEPSC	923	2,120,028
17	Information Technology	AEPSC	923	6,599,814
18	Legal GC/Administration	AEPSC	920	1,569,680
19	Administrative & General Expenses - Maintenance	AEPSC	935	344,685
20	**Non-power Goods or Services Provided for Affiliate**			
21	Materials and Supplies	OPCo	Various	1,446,854
22	Adminstrative and General Expenses - Operation	OPCo	Various	1,039,026
23	Assets and Other Debits - Utility Plant	OPCo	107, 108	2,653,232
24	Customer Accounts Expenses - Operation	OPCo	901-904	770,126
25	Customer Service and Information Expenses - Oper	OPCo	907, 908	269,769
26	Distribution Expenses - Maintenance	KPCo	593	335,368
27	Distribution Expenses - Maintenance	OPCo	590, 592-598	765,549
28	Distribution Expenses - Operation	OPCo	Various	3,424,245
29	Other Operating Revenues	APCo	456	272,346
30	Emission Allowance Sales	I&M	158.1, 411.8	5,942,283
31	Building Rent	AEPSC	454	12,205,245
32	Materials and Supplies	WPCo	Various	495,959
33	Fleet and Vehicle Charges	AEPSC	Various	1,042,497
34	Fleet and Vehicle Charges	APCo	Various	379,130
35	Fleet and Vehicle Charges	OPCo	Various	253,530
36	Other Income & Deductions-Other Income Deductions	OPCo	Various	573,459
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative & General Expenses - Operation	AEPSC	Various	8,713,040

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 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Other Power Generation - Maintenance	AEPSC	553, 555 -557	7,531,369
4	Regulatory Services	AEPSC	920	1,159,679
5	Re-Organization	AEPSC	Various	10,520,905
6	Research and Other Services	AEPSC	Various	1,363,067
7	Risk and Strategic Initiatives	AEPSC	920	707,807
8	Steam Power Generation - Maintenance	AEPSC	510-514	1,720,445
9	Steam Power Generation - Operation	AEPSC	Various	6,268,054
10	Transmission Expenses - Maintenance	AEPSC	568-572	538,106
11	Transmission Expenses - Operation	AEPSC	560-563, 566	2,918,216
12	Treasury & Investor Relations	AEPSC	920	426,682
13	Utility Operations	AEPSC	920	3,396,154
14	Central Machine Shop	APCo	Various	396,668
15	Fleet and Vehicle Charges	APCo	Various	723,985
16	Materials and Supplies	OPCo	Various	6,919,046
17	Assets and Other Debits - Current and Acc Assets	OPCo	163	1,513,837
18	Assets and Other Debits - Utility Plant	KPCo	107, 108	329,503
19	Assets and Other Debits - Utility Plant	OPCo	107, 108	3,910,612
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer Accounts Expenses - Operations	OPCo	901-903	460,330
3	Distribution Expenses - Maintenance	OPCo	590-598	1,026,160
4	Distribution Expenses - Operation	OPCo	Various	729,692

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

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Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Power Production Exp - Steam Power Gen - Maint	OPCo	510, 512-513	339,337
6	Urea	OPCp	154	1,266,932
7	Emission Allowance Purchases	APCo	158.1	1,149,171
8	Emission Allowance Purchases	KPCo	158.1	1,898,460
9	Emission Allowance Purchases	OPCo	158.1	6,770,404
10	Factored Customer A/R Bad Debts	AEP Credit, Inc.	426.5	7,301,320
11	Factored Customer A/R Expense	AEP Credit, Inc.	426.5	4,110,400
12	Transmission Expenses - Maintenance	OPCo	568-572	1,086,593
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20	**Non-power Goods or Services Provided for Affiliate**			
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Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

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Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides sevice to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

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