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

Form 1 Approved
OMB No. 1902-0021
(Expires 6/30/2007)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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**
Kentucky Power Company	**End of** 2004/Q4

INSTRUCTIONS FOR FILING FERC FORMS 1, 1-F and 3-Q

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a 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 CFR 101), must submit Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 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).

Nonmajor means having in each of the three `previous calendar years, total annual sales of 10,000 megawatt hours or more

III. What and Where to Submit

(a) Submit Forms 1, 1-F and 3-Q electronically through the Form 1/3-Q Submission Software. Retain one copy of each report for your files.
(b) Respondents may submit the Corporate Officer Certification electronically, or file/mail an original signed Corporate Officer Certification to:

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

(c) Submit, immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 1, Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to the address in III(c) above.

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

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

(ii) 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 CFR 158.10-158.12 for specific qualifications.)

Reference Schedules	Reference 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

Insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the address indicated at III (b). Use the following form for the letter or report 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.

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

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from: Public Reference and Files Maintenance Branch Federal Energy Regulatory Commission 888 First Street, NE. Room 2A ED-12.2 Washington, DC 20426 (202).502-8371

IV. When to Submit:

Submit Form 1 according to the filing dates contained in section 18 CFR 141.1 of the Commission's regulations. Submit Form 1-F according to the filing dates contained in section 18 CFR 141.2 of the Commission's regulations. Submit Form 3-Q according to the filing dates contained in section 18 CFR 141.400 of the Commission's regulations.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the 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.public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the 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: Mr. Michael Miller, ED-30); 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 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

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 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.

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 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. Commision 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.

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 wit: ... (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 shalt 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 an 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 forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom 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 ;he 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 my prescribe the manner and form in which such reports shalt 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 *form or 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

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act .... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing .... "

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

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Power Company	02 Year/Period of Report End of 2004/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, OH 43215-2373	
05 Name of Contact Person Stephen J. Clark	06 Title of Contact Person Senior Staff Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, OH 43215-2373	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name Sandra S. Bennett 02 Title Assistant Controller	Sandra S. Bennett	04/22/2005

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.

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	
46	Transmission of Electricity by Others	332	
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
50	Research, Development and Demonstration Activities	352-353	
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	NA
53	Purchase and Sale of Ancillary Services	398	
54	Monthly Transmission System Peak Load	400	NA
55	Electric Energy Account	401	
56	Monthly Peaks and Output	401	
57	Steam Electric Generating Plant Statistics	402-403	
58	Hydroelectric Generating Plant Statistics	406-407	NA
59	Pumped Storage Generating Plant Statistics	408-409	NA
60	Generating Plant Statistics Pages	410-411	NA
61	Transmission Line Statistics Pages	422-423	
62	Transmission Lines Added During the Year	424-425	NA
63	Substations	426-427	
64	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

GENERAL INFORMATION

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

Sandra S. Bennett, 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.

Kentucky
July 21, 1919

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 - Kentucky

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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

CONTROL OVER RESPONDENT

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

American Electric Power Company, Inc. - Ownership of 100% of Respondent's Common Stock

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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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

The following table shows the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by SEC regulations) of AEP at December 31, 2004 and Mr. Fayne, who ceased being an executive officer in July, 2004 and resigned on December 31, 2004.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	**Year**	**Salary ($)(1)**	**Bonus ($)(2)**	**Other Annual Compensation $(3)**	**Restricted Stock Award ($)(4)**	**Securities Underlying Options (#)**	**LTIP Payouts $(5)**	**All Other Compensation ($)(6)(7)**
Michael G. Morris — Chairman of the board and chief executive officer of the Company; chairman of the board, president and chief executive officer of AEP and the Service Corporation; chairman of the board and chief executive officer of other AEP System companies	2004	1,123,577	1,250,000	607,553	9,228,000	149,000	-0-	178,058
Susan Tomasky — Executive vice president and chief financial officer of the Company; executive vice president-chief financial officer, assistant secretary and director of the Service Corporation; vice president and director of other AEP System companies	2004	503,846	350,000	-0-	-0-	-0-	-0-	50,791
Thomas M. Hagan — Executive vice president-AEP Utilities West and director of the Service Corporation; vice president and director of other AEP System companies	2004	443,385	241,684	58,330	-0-	-0-	-0-	141,398
Holly K. Koeppel — Executive vice president-AEP Utilities East and director of the Service Corporation; vice president and director of other AEP System companies	2004	443,385	267,217	2,404	-0-	-0-	-0-	37,304
Robert P. Powers — Executive vice president-Generation and director of the Service Corporation; vice president and director of other AEP System companies	2004	433,308	275,000	654	-0-	-0-	-0-	34,879
Henry W. Fayne — (retired) Executive vice president and director of the Service Corporation; vice president and director of other AEP System companies(8)	2004	518,961	309,000	-0-	-0-	-0-	-0-	970,895

(1) Amounts in the *Salary* column are composed of executive salaries, and additional days of pay earned for years with more than the standard 260 calendar workdays and holidays.

(2) Amounts in the *Bonus* column reflect awards under the Senior Officer Annual Incentive Compensation Plan (SOIP), except for Mr. Fayne whose 2004 bonus was paid as part of a severance agreement. Payments pursuant to the SOIP are made in the first quarter of the succeeding fiscal year for performance in the year indicated.

(3) Amounts shown in *Other Annual Compensation* include perquisites if the aggregate amount of such benefits exceeds $50,000. For Mr. Morris, the amount includes the incremental cost associated with his personal use of the Company's airplane of $250,487 and premiums for life insurance that the Company funds on his behalf of $141,403. The *Other Annual Compensation* also includes tax gross-up payments for Mr. Morris and the other named executive officers.

(4) Mr. Morris received an award of 300,000 restricted shares granted under the Company's 2000 Long-Term Incentive Plan upon his employment with AEP. The award was made on January 2, 2004. 50,000 shares vested on January 1, 2005 and 50,000 shares vest on January 1, 2006. The remaining 200,000 shares of restricted stock were granted as a replacement for certain long-term compensation that Mr. Morris forfeited from his prior employer in order to accept his position at AEP. These shares vest, subject to his continued employment, in three equal components on November 30, 2009, November 30, 2010 and November 30, 2011, respectively. The value of the restricted stock as of December 31, 2004 ($10,302,000) is determined by multiplying the total number of shares held by the closing price of AEP Common Stock on the New York Stock Exchange on December 31, 2004. Dividends are paid on all restricted shares at the same rate as paid on AEP's Common Stock.

(5) Amounts in the *Long-Term Compensation — Payouts* column generally reflect phantom stock units resulting from performance share units issued under the AEP 2000 Long-Term Incentive Plan. However, no shares were earned under this or any other plan in the periods shown. The December 10, 2003 through December 31, 2004 performance period did result in an award score of 123.1% of the target award and accrued dividends. However, these shares have not vested and will not generally vest until December 31, 2006, subject to the participant's continued employment. Therefore, the payout for these performance shares will be reported for 2006 if and when they vest.

(6) Amounts in the *All Other Compensation column*, except for additional compensation to Messrs. Morris and Fayne disclosed in footnotes (7) and (8), include (i) AEP's matching contributions under the AEP Retirement Savings Plan and the AEP Supplemental Retirement Savings Plan, a non-qualified plan designed to supplement the AEP Retirement Savings Plan; (ii) relocation and temporary living expenses and (iii) subsidiary companies' director fees. Detail of the included in the *All Other Compensation* column is shown below.

Item	**Mr. Morris**	**Ms. Tomasky**	**Mr. Hagan**	**Ms. Koeppel**	**Mr. Powers**	**Mr. Fayne**
Savings Plan Matching Contributions	$ 6,534	$ 6,888	$ 8,850	$ 9,225	$ 7,283	$ 6,793
Supplemental Savings Plan Matching Contributions	41,712	27,103	21,626	18,429	16,546	27,892
Relocation and Temporary Living Expenses	27,250	-0-	101,972	-0-	-0-	-0-
Subsidiary Director Fees	17,400	16,800	8,950	9,650	11,050	16,200

(7) Club initiation fees of $85,163 were included in the *All Other Compensation* column for Mr. Morris.

(8) In July 2004, AEP realigned its management team and Mr. Fayne ceased being an executive officer of AEP and was assigned other responsibilities. He left active employment on December 31, 2004 with 31 years of service and, as a result, was paid severance compensation of $814,039 and accrued vacation pay of $105,971 that is included in the *All Other Compensation* column. He also received a bonus of $309,000, which is included in the *Bonus* column.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Michael G. Morris, Chairman of the Board	Columbus, Ohio
2	Chief Executive Officer	
3		
4	Jeffrey D. Cross, Assistant Secretary	Columbus, Ohio
5		
6	E. Linn Draper, Jr	Columbus, Ohio
7		
8	Carl L. English, Vice President	Columbus, Ohio
9		
10	Henry W. Fayne, President	Columbus, Ohio
11		
12	Thomas M. Hagan, Vice President	Columbus, Ohio
13		
14	John B. Keane	Columbus, Ohio
15		
16	Holly Keller Koeppel, Vice Chairman of the Board	Columbus, Ohio
17	Vice President	
18		
19	Venita McCellon-Allen	Columbus, Ohio
20		
21	Armando A. Pena, Vice President	Columbus, Ohio
22		
23	Robert P. Powers, Vice President	Columbus, Ohio
24		
25	Thomas V. Shockley, III, Vice President	Columbus, Ohio
26		
27	Stephen P. Smith, Vice President	Columbus, Ohio
28	Treasurer	
29		
30	Susan Tomasky, Vice President	Columbus, Ohio
31		
32	Note: The Respondent does not have an Executive Committee	
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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 Renewed	Community	Period of Franchise & Termination	Consideration
Renewed March 9, 2004	Coal Run Village, Pike County, KY	20 years; expires March 8, 2024	Annual sum equal to 25% of amount paid by City for street lighting purposes (excluding any tax, fuel adjustment) during the preceding 12 months
Renewed May 10, 2004	City of Worthington, Greenup County, KY	20-years; expires May 9, 2024	Value varies based on number of active streetlights – approx. $1,860 per year
Renewed September 23, 2004	Russell, Greenup County, KY	20 years; expires September 22, 2024	“Kentucky Power Company shall pay an annual sum equal to 25% of the total amount, excluding any applicable tax and/or any applied fuel clause adjustment, paid by the City to Kentucky Power Company for street lighting purposes during the preceding twelve months. Each annual payment will be made within forty-five (45) days after each annual anniversary of the effective date of the franchise.”

2. None

3. None

4. None

5. None

6. Kentucky Public Service Commission Case No. 2002-00324:
   $20,000,000 Promissory Note dated February 5,2004 due 2015

   SEC File No. 70-10166 under the Public Utility Holding Company Act of 1935:
   Short-term borrowing authority not to exceed $200,000,000 through March 31, 2007.

7. None

8. The 2004 wage agreements resulted in a general increase of 3.0% for represented employees.

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

10. None

11. (Reserved)

12. Not Applicable

13. Michael G. Morris was elected as Director, Chairman of the Board and Chief Executive Officer effective January 1, 2004.

    E. Linn Draper, Jr. resigned as Director effective February 24, 2004.

    Stephen P. Smith was elected as Director and Vice President effective on January 28, 2004.

    Stephan T. Haynes was elected Assistant Treasurer effective as of May 3, 2004.

    Thomas M. Hagan resigned as Director and Vice President effective June 1, 2004.

    Holly Keller Koeppel was elected as Director and as Vice Chairman of the Board effective June 1, 2004.

    Henry W. Fayne resigned as President effective June 1, 2004. He resigned as Director effective December 30, 2004

    Timothy C. Mosher resigned as Vice President and was elected as President effective June 1, 2004.

    Marsha P. Ryan resigned as Vice President effective June 1, 2004.

    Gene M. Jenson's title was changed from Vice President to Vice President-Distribution Region Operations effective June 21, 2004.

13. Continued

Carl L. English was elected as Director and as Vice President effective August 1, 2004.

Glenn M. Files resigned as Vice President effective September 10, 2004.

Venita McCellon-Allen was elected as Director effective September 22, 2004.

Jeffrey D. Cross resigned as Director effective July 29, 2004.

John B. Keane was elected as Director effective July 29, 2004

Thomas V. Shockley, III resigned as Director and as Vice President effective July 30, 2004.

Coulter R. Boyle, III was elected as Vice President effective August 20, 2004.

Charles E. Zebula was elected as Vice President effective August 20, 2004.

Timothy A. King resigned as Secretary effective December 15, 2004

Heather L. Geiger appointed Secretary effective December 15, 2004

Armando A. Pena resigned as Director and Vice President effective December 30, 2004

14. Proprietary capital ratio exceeds 30%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	1,338,164,094	1,325,015,878
3	Construction Work in Progress (107)	200-201	16,544,432	17,322,607
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,354,708,526	1,342,338,485
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	419,847,987	400,608,560
6	Net Utility Plant (Enter Total of line 4 less 5)		934,860,539	941,729,925
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)		934,860,539	941,729,925
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		996,378	974,253
19	(Less) Accum. Prov. for Depr. and Amort. (122)		152,621	145,952
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	9,665,686	7,754,412
24	Other Investments (124)		5,016,298	5,616,286
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)		19,062,736	16,134,242
31	Long-Term Portion of Derivative Assets – Hedges (176)		4,296	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		34,592,773	30,333,241
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		127,301	863,169
36	Special Deposits (132-134)		1,959,690	2,659,669
37	Working Fund (135)		5,000	22,898
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		16,388,056	17,793,159
41	Other Accounts Receivable (143)		5,108,472	2,769,573
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		33,659	736,032
43	Notes Receivable from Associated Companies (145)		16,126,733	0
44	Accounts Receivable from Assoc. Companies (146)		23,045,902	25,327,058
45	Fuel Stock (151)	227	6,404,680	9,240,156
46	Fuel Stock Expenses Undistributed (152)	227	145,892	240,961
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	5,851,880	5,644,924
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	13,199,135	10,940,004

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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		9,665,686	7,754,412
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)		819,381	669,690
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		727,966	711,796
61	Accrued Utility Revenues (173)		7,340,252	5,533,840
62	Miscellaneous Current and Accrued Assets (174)		962,112	1,026,407
63	Derivative Instrument Assets (175)		34,753,787	31,505,082
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		19,062,736	16,134,242
65	Derivative Instrument Assets - Hedges (176)		4,158,573	829,157
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		4,296	0
67	Total Current and Accrued Assets (Lines 34 through 66)		108,358,435	91,152,857
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,515,726	4,530,229
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	123,973,052	120,554,619
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,871,937	3,871,937
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	11,409,228	10,076,276
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)		1,020,709	1,088,091
82	Accumulated Deferred Income Taxes (190)	234	39,511,130	35,264,271
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		183,301,782	175,385,423
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,261,113,529	1,238,601,446

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☐ A Rresubmission	/ /	end of 2004/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	50,450,000	50,450,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	208,750,000	208,750,000
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)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	70,555,280	64,150,583
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-8,774,970	-6,212,395
16	Total Proprietary Capital (lines 2 through 15)		320,980,310	317,138,188
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	80,000,000	60,000,000
21	Other Long-Term Debt (224)	256-257	428,578,427	427,964,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		268,125	362,375
24	Total Long-Term Debt (lines 18 through 23)		508,310,302	487,601,625
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,801,941	3,548,993
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		74,306	350,639
29	Accumulated Provision for Pensions and Benefits (228.3)		17,654,883	13,648,855
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		13,125,539	11,904,064
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		358,811	458,775
34	Asset Retirement Obligations (230)		0	0
35	Total Other Noncurrent Liabilities (lines 26 through 34)		34,015,480	29,911,326
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		20,080,483	22,802,343
39	Notes Payable to Associated Companies (233)		0	38,095,519
40	Accounts Payable to Associated Companies (234)		24,899,025	22,647,842
41	Customer Deposits (235)		12,308,488	9,894,337
42	Taxes Accrued (236)	262-263	9,248,179	7,329,064
43	Interest Accrued (237)		6,754,333	6,915,363
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☐ A Rresubmission	/ /	end of 2004/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,247,633	1,106,923
48	Miscellaneous Current and Accrued Liabilities (242)		7,788,852	7,521,823
49	Obligations Under Capital Leases-Current (243)		1,560,983	1,742,671
50	Derivative Instrument Liabilities (244)		27,633,969	23,363,072
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		13,125,539	11,904,064
52	Derivative Instrument Liabilities - Hedges (245)		3,055,808	703,351
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		358,811	458,775
54	Total Current and Accrued Liabilities (lines 37 through 53)		101,093,403	129,759,469
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		59,971	49,852
57	Accumulated Deferred Investment Tax Credits (255)	266-267	6,721,725	7,954,776
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	675,458	365,734
60	Other Regulatory Liabilities (254)	278	22,209,994	18,435,072
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	19,268,201	0
63	Accum. Deferred Income Taxes-Other Property (282)		159,346,808	160,970,328
64	Accum. Deferred Income Taxes-Other (283)		88,431,877	86,415,076
65	Total Deferred Credits (lines 56 through 64)		296,714,034	274,190,838
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,261,113,529	1,238,601,446

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STATEMENT OF INCOME

1. Enter in column (e) operations for the reporting quarter and in column (f) the operations for the same three month period for the prior year.
2. Report in Column (g) year to date amounts for electric utility function; in column (i) the year to date amounts for gas utility, and in (k) the year to date amounts for the other utility function for the current quarter/year.
3. Report in Column (h) year to date amounts for electric utility function; in column (j) the year to date amounts for gas utility, and in (l) the year to date amounts for the other utility function for the previous quarter/year.
4. If additional columns are needed place them in a footnote.

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	445,487,488	416,470,545		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	295,663,956	262,995,673		
5	Maintenance Expenses (402)	320-323	32,801,872	27,327,890		
6	Depreciation Expense (403)	336-337	35,339,258	36,025,829		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,858,878			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,003,416	2,627,991		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		606,768	616,440		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	9,144,646	8,788,584		
15	Income Taxes - Federal (409.1)	262-263	-3,485,727	-6,919,664		
16	- Other (409.1)	262-263	-302,792	-89,255		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	50,300,066	136,736,031		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	35,374,277	115,552,977		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,233,051	-1,168,400		
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,113	980		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		2,882,507	1,243,959		
23	Losses from Disposition of Allowances (411.9)		451	1,267		
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		388,478,460	350,183,086		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		57,009,028	66,287,459		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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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
445,487,488	416,470,545					2
						3
295,663,956	262,995,673					4
32,801,872	27,327,890					5
35,339,258	36,025,829					6
3,858,878						7
4,003,416	2,627,991					8
38,616	38,616					9
						10
						11
606,768	616,440					12
						13
9,144,646	8,788,584					14
-3,485,727	-6,919,664					15
-302,792	-89,255					16
50,300,066	136,736,031					17
35,374,277	115,552,977					18
-1,233,051	-1,168,400					19
1,113	980					20
						21
2,882,507	1,243,959					22
451	1,267					23
						24
388,478,460	350,183,086					25
57,009,028	66,287,459					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		57,009,028	66,287,459		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		26,366	30,112		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,397	21,245		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)			80		
35	Nonoperating Rental Income (418)		39,047	57,504		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		461,907	39,100		
38	Allowance for Other Funds Used During Construction (419.1)		244,180	970,437		
39	Miscellaneous Nonoperating Income (421)		1,140,345	-5,183,061		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,909,448	-4,107,233		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,061,721	31,794		
44	Miscellaneous Amortization (425)	340	2			
45	Donations (426.1)	340	490,356	319,101		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-306,890	307,731		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		206,524	166,275		
49	Other Deductions (426.5)		3,324,982	2,602,888		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,776,695	3,427,789		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	275			
53	Income Taxes-Federal (409.2)	262-263	918,758	-2,213,660		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,652,452	36,369,387		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,804,040	37,445,339		
57	Investment Tax Credit Adj.-Net (411.5)			-41,488		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,232,555	-3,331,100		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-1,634,692	-4,203,922		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		27,051,137	26,466,534		
63	Amort. of Debt Disc. and Expense (428)		1,108,752	1,133,543		
64	Amortization of Loss on Reaquired Debt (428.1)		67,382	53,365		
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)	340	306,065	905,050		
68	Other Interest Expense (431)	340	1,170,768	784,111		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		234,460	722,861		
70	Net Interest Charges (Total of lines 62 thru 69)		29,469,644	28,619,742		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		25,904,692	33,463,795		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)			1,743,914		
75	Net Extraordinary Items (Total of line 73 less line 74)			-1,743,914		
76	Income Taxes-Federal and Other (409.3)	262-263		-610,370		
77	Extraordinary Items After Taxes (line 75 less line 76)			-1,133,544		
78	Net Income (Total of line 71 and 77)		25,904,692	32,330,251		

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		64,150,583	48,268,596
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		25,904,692	32,330,251
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			-19,499,995	(16,448,264)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-19,499,995	(16,448,264)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		70,555,280	64,150,583
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)		70,555,280	64,150,583
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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)	25,904,692	32,330,251
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	43,240,168	38,692,436
5	Amortization of Regulatory Debits	606,768	616,440
6			
7	Mark to Market of Risk Management Contracts	1,022,192	15,111,731
8	Deferred Income Taxes (Net)	12,774,201	20,107,102
9	Investment Tax Credit Adjustment (Net)	-1,233,051	-1,209,888
10	Net (Increase) Decrease in Receivables	628,817	2,677,533
11	Net (Increase) Decrease in Inventory	2,723,589	1,076,851
12	Net (Increase) Decrease in Allowances Inventory	-2,259,131	-198,815
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,287,408	-36,073,011
14	Net (Increase) Decrease in Other Regulatory Assets	-1,260,759	1,680,824
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,163,753	-1,560,693
16	(Less) Allowance for Other Funds Used During Construction	244,180	970,437
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	5,306,291	-12,586,854
19	Extraordinary Items after Taxes		1,133,544
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	89,660,758	60,827,014
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-38,474,805	-81,706,616
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	-244,180	-970,437
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-38,230,625	-80,736,179
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,538,348	966,992
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)		

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		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Change in Other Cash Deposits, Net	17,898	-4,150
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-36,674,379	-79,773,337
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	20,000,000	75,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long-Term Debt Issuance Expense		-736,575
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Notes Payable to Associated Companies		14,709,425
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	20,000,000	88,972,850
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-55,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79	Notes Payable/Receivable to Associated Companies	-54,222,252	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-19,499,995	-16,448,264
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-53,722,247	17,524,586
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-735,868	-1,421,737
87			
88	Cash and Cash Equivalents at Beginning of Period	863,169	2,284,906
89			
90	Cash and Cash Equivalents at End of period	127,301	863,169

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

Other Assets:		
Utility Plant	565,675	
Other Property & Investments	582,743	
Current Assets & Accrued Assets	457,830	
Accrued Utility Revenues	(1,806,412)	
Deferred Property Taxes	(188,300)	
Deferred Debits	730,882	
Total Other Assets		342,418
Other Liabilities:		
Accum. Other Comprehensive Income	(583,748)	
Noncurrent Liabilities	(1,407,966)	
Current & Accrued Liabilities	2,640,202	
Deferred Credits	3,606,708	
Other	708,677	
Total Other Liabilities		4,963,873
Total Other		**5,306,291**

Schedule Page: 120 Line No.: 18 Column:

Other Assets		
Other Deferred Debits	(2,896,980)	
Loss on Reacquired Debt	(936,257)	
Special Deposits	(2,398,894)	
Deferred Property Taxes	(547,200)	
Accrued Utility Revenues	(232,482)	
Other	(1,056,957)	
Total Other Assets		(8,068,770)
Other Liabilities		
Other Deferred Credits	(591,546)	
Accum Provisions - Misc	(8,226,103)	
Paid In Capital - OCI	97,963	
Customer Deposits	1,845,604	
Other Current Liabilities	(3,537,770)	
Other	5,893,768	
Total		(4,518,084)
Total Other		**(12,586,854)**

Schedule Page: 120 Line No.: 19 Column:

Cumulative Effect of Change in Accounting Principle

Extraordinary Deductions (435)	1,743,914
Income Taxes - Federal and State (409.3)	(610,370)
	1,133,544

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 FOOTNOTES

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 electric utility subsidiary of AEP.
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 domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
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.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	The Clean Air Act.
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	Restated and Amended Operating Agreement originally dated as of January 1, 1997 between the AEP West companies and AEPSC.
DETM	Duke Energy Trading and Marketing L.L.C., a nonaffiliated risk management counterparty.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
Parent	American Electric Power Company, Inc.

PJM	PJM Interconnection, LLC; a regional transmission organization.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges, and nonderivative contracts held for trading purposes.
RTO	Regional Transmission Organization.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SFAS 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.
SPP	Southwest Power Pool.
Utility Money Pool	AEP System's Utility Money Pool.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. We are subject to regulation by the FERC under the Federal Power Act. We are subject to further regulation with regard to rates and other matters by the KPSC. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives. We engage in wholesale electricity marketing and risk management activities in the United States.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities under existing power pool and system integration agreements. 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. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of each year.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due 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.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

As a subsidiary of AEP, we are subject to regulation by the SEC under the PUHCA. Our rates are approved by the FERC and the KPSC. The FERC regulates wholesale electricity operations. Wholesale power markets are generally market-based and are not cost-based regulated unless a generator/seller of wholesale power is determined by the FERC to have “market power.” The FERC also regulates transmission service and rates. The KPSC regulates our retail operations and retail rates.

Basis of Accounting

Our accounting is subject in certain respects to both the requirements of the KPSC 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 classification of cumulative effect of accounting changes as extraordinary items, the requirement to report deferred tax assets and liabilities separately rather than as a single amount, recording expenses for factored customer accounts receivable and accrued utility revenues as miscellaneous income deductions instead of as operating expenses and classifying accrued asset removal costs as accumulated depreciation instead of as liabilities.

Accounting for the Effects of Cost-Based Regulation

As a cost-based rate-regulated electric public utility company, our financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, “Accounting for the Effects of Certain Types of Regulation”, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded 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.

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, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension 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 differ from those estimates.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses.

We implemented SFAS 143 effective January 1, 2003 (see "Accounting for Asset Retirement Obligations" section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet certain criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets."

The fair value of an asset is the amount at which that asset 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 in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Depreciation

We provide for depreciation of property, plant and equipment 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 generally used for the year 2004 and 2003:

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2004	3.8	1.7	3.5	9.2
2003	3.8	1.7	3.5	7.1

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, Temporary Cash Investments, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

We value fossil fuel inventories at the lower of a weighted average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our 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, we accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billings.

AEP Credit factors our accounts receivable.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes. See Note 4 for the amount of deferred fuel costs.

In general, changes in fuel costs in Kentucky are reflected in rates in a timely manner through the fuel cost adjustment clauses. All or a portion of profits from off-system sales are shared with ratepayers through fuel clauses in Kentucky.

Revenue Recognition

Regulatory Accounting

The financial statements of cost-based rate-regulated operations 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 to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains and losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, 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, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred. Since the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity and coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where we the AEP System owns assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps.

In October 2002, EITF 02-3 precluded MTM accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all nonderivative wholesale and risk management transactions occurring on or after October 25, 2002. For nonderivative risk management transactions entered prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as an extraordinary item (see “Accounting for Risk Management Contracts” section of Note 2).

After January 1, 2003, revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in the financial statements on a net basis. Since we are subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

We participate in wholesale marketing and risk management activities in electricity and gas. When the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as a hedge of a forecasted transaction, a future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the financial statements in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative’s gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the financial statements immediately (see Note 10).

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

We use 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 have been 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 being amortized over the life of the regulated plant investment.

Excise Taxes

As an agent for some state and local governments, we collect from customers certain excise taxes levied by those state or local governments on customers. We do not record these taxes as revenue or expense.

Debt

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

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The amortization expense is included in interest charges.

Goodwill and Intangible Assets

We have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2004 and 2003.

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. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income is included on the balance sheet in the proprietary capital section. Accumulated Other Comprehensive Income as of December 31, 2004 and 2003 is shown in the following table.

	December 31,	
	2004	**2003**
	(in thousands)	
Components		
Cash Flow Hedges	$ 813	$ 420
Minimum Pension Liability	(9,588)	(6,633)

Earnings Per Share (EPS)

As a wholly-owned subsidiaries of AEP, we are not required to report EPS.

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEMS

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2004 that we have determined relate to our operations.

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

We implemented FASB Staff Position (FSP) FAS 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,” effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which we previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. See Note 9 for additional information related to the effects of implementation of FAS 106-2 on our postretirement benefit plans.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) 25. The statement is effective as of the first interim or annual period beginning after June 15, 2005, with early implementation permitted. An extraordinary item is recorded for the effect of initially applying the statement.

We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

SFAS 153 "Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153, "Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29" to eliminate the Opinion 29 exception to fair value for nonmonetary exchanges of similar productive assets and to replace it with a general exception for exchange transactions that do not have commercial substance. We expect to implement SFAS 153 prospectively, beginning July 1, 2005. We do not expect the effect to be material to our results of operations, cash flows or financial condition.

FASB Staff Position 109-1 "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Activities Provided by the American Jobs Creation Act of 2004"

On October 22, 2004, the American Jobs Creation Act of 2004 (Act) was signed into law. The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9 percent (when fully phased-in in 2010) on a percentage of "qualified production activities income." Beginning in 2005 and for 2006, the deduction is 3 percent of qualified production activities income. The deduction increases to 6 percent for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. While the U.S. Treasury has issued general guidance on the calculation of the deduction, this guidance lacks clarity as to determination of qualified production activities income as it relates to utility operations. We believe that the special deduction for 2005 and 2006 will not materially affect results of operations, cash flows, or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, asset retirement obligations, fair value measurements, business combinations, revenue recognition, pension plans, liabilities and equity, earnings per share calculations, accounting changes and related tax impacts as applicable. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

EXTRAORDINARY ITEM

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 "Accounting for Contracts Included in Energy Trading and Risk Management Activities," and related interpretive guidance. We recorded pretax and after tax loss of $1.7 million and $1.1 million, respectively, against net income in extraordinary item in the first quarter of 2003. These amounts are recognized as the positions settle.

3. RATE MATTERS

Stipulation and Settlement Agreement

On October 25, 2004, KPCo filed an application requesting the KPSC to approve the terms and provisions of a Stipulation and Settlement Agreement among KPCo, the Office of the Kentucky Attorney General and the Kentucky Industrial Utility Customers. The Stipulation: (1) extends a unit power agreement for approximately 18 years, until December 7, 2022, which obligates KPCo to pay 15 percent of the costs associated with two 1,300 MW generating units in Rockport, Indiana for 15 percent of the units' generating output; (2) modifies KPCo's off-system sales clause tariff to reflect as an expense the environmental costs attributable to off-system sales; and (3) establishes a schedule for KPCo to file its next integrated resource plan, and provides for retail rate recovery of supplemental payments associated with the extension of the unit power agreement and the settlement of other regulatory matters. On December 13, 2004, the KPSC issued its order approving the terms and provisions of the Stipulation and Settlement Agreement. The FERC approved the extension of the unit power agreement on December 29, 2004. KPCo will recover an additional $5 million annually during the first five years and $6 million annually for the remaining 13 years of the 18- year extension.

Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the CAA.

RTO Formation/Integration

Based on FERC approvals in response to nonaffiliated companies' requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving the AEP East companies continued deferral of both Alliance RTO formation costs and PJM integration costs, including the deferral of a carrying charge thereon. We have deferred approximately $2.4 million of RTO formation and integration costs and related carrying charges through December 31, 2004.

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the OATT to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of the AEP East companies' portion of the OATT as these companies file rate cases.

In August 2004, the AEP East companies filed an application with the FERC dividing the RTO formation/integration costs between PJM-incurred integration costs billed to them including related carrying charges, and all other RTO formation/integration costs. AEP East companies intend to file with the FERC to request that deferred PJM-incurred integration costs billed to them be recovered from all PJM customers. Management anticipates the other RTO formation/integration costs will be recovered through transmission rates in the AEP East zone. The AEP East companies will be responsible for paying most of the amount allocated by the FERC to the AEP East zone since it will be attributable to their internal load. In the August 2004 application, the AEP East companies requested permission to amortize over 15 years beginning January 1, 2005 the cost to be billed within the AEP East zone which represents approximately one-half of the total deferred RTO formation/integration costs. The AEP East companies also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, but the AEP East companies did not propose an amortization period in the application. The FERC has not ruled on the application.

The AEP East companies integrated into PJM on October 1, 2004. The AEP East companies intend to file a joint request with other new PJM members to recover approximately one-half of the deferred RTO formation/integration costs (i.e. the PJM-incurred integration expenses billed to the AEP East companies) through a new charge in the PJM OATT that would apply to all loads and generation in the PJM region during a 10-year period beginning in May 2005. The AEP East companies will expense their portion of the PJM-incurred integration costs billed by PJM under the new charge. The AEP East companies will amortize the remaining portion of our RTO formation/integration costs over the period to be approved by the FERC and seek recovery of such costs in the retail rates for each of the AEP East companies' state jurisdictions. Management believes that it is probable that the FERC will approve recovery of the PJM-incurred integration costs to be billed to the AEP East companies through the PJM OATT and that the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM incurred RTO formation/integration costs in the AEP East retail jurisdictions. If the FERC ultimately decides not to approve an amortization period that would provide the AEP East companies with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of these deferred costs the AEP East companies' future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs' revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO Participants, including AEP East companies, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO Participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC is expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that the AEP East companies previously recovered from T&O service customers to mainly AEP's native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP East companies for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP East companies accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP East companies and Exelon filed joint comments and protests with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an order indicating that the SECA transition rates would be subject to refund or surcharge and set for hearing all remaining aspects of the compliance filings to the November 18 order, including AEP's request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues within the PJM/MISO Expanded Footprint for the twelve months ended September 30, 2004, the last twelve months prior to the AEP East companies joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP East companies for their lost T&O revenues through March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding

In its July 2002 order conditionally accepting the AEP East companies' choice to join PJM, the FERC directed AEP East companies, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO. In December 2003, AEP East companies and ComEd jointly filed a hold-harmless proposal, which was rejected by the FERC in March 2004 without prejudice to the filing of a new proposal.

In July 2004, AEP East companies and PJM filed jointly with the FERC a new hold-harmless proposal that was nearly identical to a proposal filed jointly by ComEd and PJM in April 2004. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for April 2005.

The proposed hold-harmless agreement as filed by PJM and AEP East companies specifies that the term of the agreement commences on October 1, 2004 and terminates when the FERC determines that effective internalization of congestion and loop flows is accomplished. The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 to $70 million over the term of the agreement for ComEd and AEP East companies. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP East companies and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP East companies and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 which is pending approval before the FERC.

At this time, management is unable to predict the outcome of this proceeding. AEP East companies will support vigorously its positions before the FERC. No provision has been established. If the FERC ultimately approves a significant hold-harmless payment to the Michigan and Wisconsin utilities, it would adversely impact results of operations and cash flows.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a "pivotal supplier" test which determines if the market load can be fully served by alternative suppliers and a "market share" test which compares the amount of surplus generation at the time of the applicant's minimum load. In July 2004, the FERC issued an order on rehearing, affirming its conclusions in the April order and directing the AEP System and two nonaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, as amended on September 16, 2004 and November 19, 2004, the AEP System submitted its generation market power screens in compliance with the FERC's orders. The analysis focused on the three major areas in which AEP subsidiaries serve load and own generation resources -- ECAR, SPP and ERCOT, and the "first tier" control areas for each of those areas.

The pivotal supplier and market share screen analyses that were filed demonstrated that the AEP System does not possess market power in any of the control areas to which it is directly connected (first-tier markets). The AEP System passed both screening tests in all of its "first tier" markets. In its three "home" control areas, the AEP System passed the pivotal supplier test. The AEP East companies, as part of PJM, also passed the market share screen for the PJM destination market.

In a December 17, 2004 order, FERC affirmed the conclusions that the AEP System passed both market power screen tests in all areas except SPP.

In addition to FERC market monitoring, the AEP East companies are subject to market monitoring oversight by the RTOs in which they are a member, including PJM. These market monitors have authority for oversight and market power mitigation.

Management believes that the AEP System is unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows of the FERC's and PJM's market power analysis cannot be determined.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items at December 31:

	2004	2003	Recovery/Refund Period
	(in thousands)		
Regulatory Assets:			
SFAS 109 Regulatory Asset	$ 110,436	$ 107,672	Various Periods (a)
Other	13,537	12,883	Various Periods (a)
Total FERC Account 182.3 Regulatory Assets	$ 123,973	$ 120,555	
Unamortized Loss on Reacquired Debt (c)	$ 1,021	$ 1,088	Up to 28 Years (b)
Regulatory Liabilities:			
SFAS 109 Regulatory Liability	$ 6,588	$ 7,844	Various Periods (a)
Unrealized Gain on Forward Commitments	13,041	9,174	Various Periods (a)
Other	2,581	1,417	Various Periods (a)
Total FERC Account 254 Regulatory Liabilities	$ 22,210	$ 18,435	
Deferred Investment Tax Credits (c)	$ 6,722	$ 7,955	Up to 16 Years (a)

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) Recorded in an account other than regulatory asset or liability on the balance sheet.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. In connection with the merger, nonrecoverable merger costs were expensed in 2003. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were nonrecoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense. Deferred merger costs are included in Other Regulatory Assets in the above tables.

The Kentucky settlement agreement provides for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions of $28 million which began in the third quarter of 2000.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See "Merger Litigation" section of Note 5 for information on a court decision concerning the merger.

5. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Our estimated construction expenditures for 2005 including amounts for proposed environmental rules are $56.1 million. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

We have entered into long-term contracts to acquire fuel for electric generation. The expiration date of our longest fuel contract is 2008. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

Potential Uninsured Losses

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 which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be “physically interconnected” and confined to a “single area or region.” In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy

In 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron’s bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron’s bankruptcy.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP’s offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. AEP asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron’s claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management’s analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows or financial condition.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were “high-priced.” The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities had filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ’s decision. The utilities’ request for a rehearing was denied. The utilities’ appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered subsequent to December 31, 2002 in accordance with FIN 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

We enter into certain types of contracts, which would 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. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and 2003, we entered into sale agreements which included indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications entered during 2004 or 2003.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East and West companies and for activity conducted pursuant to the system integration agreement.

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2004, the maximum potential loss for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is $1 million.

7. DISPOSITIONS

2003

Water Heater Assets

The AEP East companies participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. We sold our water heater rental program and recorded a pretax loss of $11 thousand in the first quarter of 2003.

8. BENEFIT PLANS

We participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, we participate in other postretirement benefit plans sponsored by AEP to provide medical and life insurance benefits for retired employees. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004 (see "FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" section of Note 2). The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million for the AEP plan contributing to its actuarial gain in 2004. The tax-free subsidy reduced 2004's net periodic postretirement benefit cost for the AEP plan by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

Our reduction in the net periodic postretirement cost for 2004 was $690 thousand.

The following tables provide a reconciliation of the changes in the AEP plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2004, and a statement of the funded status as of December 31 for both years:

AEP Pension Obligations, Plan Assets, Funded Status as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 3,688	$ 3,583	$ 2,163	$ 1,877
Service Cost	86	80	41	42
Interest Cost	228	233	117	130
Participant Contributions	-	-	18	14
Actuarial (Gain) Loss	379	91	(130)	192
Benefit Payments	(273)	(299)	(109)	(92)
Projected Obligation at December 31	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,180	$ 2,795	$ 950	$ 723
Actual Return on Plan Assets	409	619	98	122
Company Contributions (a)	239	65	136	183
Participant Contributions	-	-	18	14
Benefit Payments (a)	(273)	(299)	(109)	(92)
Fair Value of Plan Assets at December 31	$ 3,555	$ 3,180	$ 1,093	$ 950
Funded Status:				
Funded Status at December 31	$ (553)	$ (508)	$ (1,007)	$ (1,213)
Unrecognized Net Transition Obligation	-	2	179	206
Unrecognized Prior Service Cost (Benefit)	(9)	(12)	5	6
Unrecognized Net Actuarial Loss	1,040	797	795	977
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

(a) AEP's contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Amounts Recognized in AEP's Balance Sheet as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
		(in millions)		
Prepaid Benefit Costs	$ 524(a)	$ 325	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(28)	(24)
Additional Minimum Liability	(566)	(723)	N/A	N/A
Intangible Asset	36	39	N/A	N/A
Pretax Accumulated Other Comprehensive Income	530	684	N/A	N/A
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

N/A = Not Applicable

(a) Includes $386 million related to the qualified plan that became fully funded upon receipt of the December 2004 discretionary contribution.

Pension and Other Postretirement Plans' Assets:

The asset allocations for AEP's pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentages)**	
Equity Securities	70	68	71
Debt Securities	28	25	27
Cash and Cash Equivalents	2	7	2
Total	100	100	100

The asset allocations for AEP's other postretirement benefit plans at the end of 2004 and 2003, and target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentages)**	
Equity Securities	70	70	61
Debt Securities	28	28	36
Other	2	2	3
Total	100	100	100

AEP's investment strategy for their employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate. Because of a $200 million discretionary contribution at the end of 2004, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2005.

The value of AEP's pension plans' assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The qualified plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits).

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation:	**2004**	**2003**
	(in millions)	
Qualified Pension Plans	$ 3,918	$ 3,549
Nonqualified Pension Plans	80	76
Total	$ 3,998	$ 3,625

Minimum Pension Liability:

AEP's combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $553 million at December 31, 2004. For AEP's 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, 2004 and 2003 were as follows:

	Underfunded Pension Plans	
End of Year	**2004**	**2003**
	(in millions)	
Projected Benefit Obligation	$ 2,978	$ 3,688
Accumulated Benefit Obligation	2,880	3,625
Fair Value of Plan Assets	2,406	3,180
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	474	445

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	2003
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

AEP intends to make additional discretionary contributions of approximately $100 million per quarter in 2005 to meet its goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations:

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

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in percentages)			
Discount Rate	5.50	6.25	5.80	6.25
Rate of Compensation Increase	3.70	3.70	N/A	N/A

The method used to determine the discount rate that AEP utilizes for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, AEP changed to a duration based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for pension plans and 5.80% for other postretirement benefit plans.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

AEP Estimated Future Benefit Payments and Contributions:

Information about the expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2005**	**2004**	**2005**	**2004**
		(in millions)		
Required Contributions (a)	$17	$31	N/A	N/A
Additional Discretionary Contributions	400 (b)	200 (b)	$142	$137

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor.
(b) Contribution in 2004 and expected contribution in 2005 in excess of the required contribution to fully fund AEP's qualified pension plans by the end of 2005.

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans' trust is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The table below reflects the total benefits expected to be paid from the plan or from AEP's assets, including both AEP's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2005	$ 293	$ 115	$ -
2006	302	122	(9)
2007	317	131	(10)
2008	327	140	(11)
2009	348	151	(12)
Years 2010 to 2014, in Total	1,847	867	(72)

Components of Net Periodic Benefit Cost:

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2004, 2003 and 2002:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
		(in millions)		
Service Cost	$ 86	$ 80	$ 41	$ 42
Interest Cost	228	233	117	130
Expected Return on Plan Assets	(292)	(318)	(81)	(64)
Amortization of Transition (Asset) Obligation	2	(8)	28	28
Amortization of Prior Service Cost	(1)	(1)	-	-
Amortization of Net Actuarial (Gain) Loss	17	11	36	52
Net Periodic Benefit Cost (Credit)	40	(3)	141	188
Capitalized Portion	(10)	(3)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 30	$ (6)	$ 95	$ 145

Net Pension Cost:

Our net periodic benefit cost (credit) for the pension plan was $0.6 million and $(0.6) million for fiscal years 2004 and 2003, respectively.

Our net periodic benefit cost (credit) for the other postretirement benefit plan was $3.0 million and $4.0 million for fiscal years 2004 and 2003, respectively.

Actuarial Assumptions for Net Periodic Benefit Costs:

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

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
		(in percentages)		
Discount Rate	6.25	6.75	6.25	6.75
Expected Return on Plan Assets	8.75	9.00	8.35	8.75
Rate of Compensation Increase	3.70	3.70	N/A	N/A

The expected return on plan assets for 2004 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	**2004**	**2003**
Initial	10.0 %	10.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2008

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

	1% Increase	**1% Decrease**
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 27	$ (21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	302	(245)

Retirement Savings Plan

We participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, we participated in two large AEP sponsored defined contribution retirement savings plans. The contributions to the plan are 75% of the first 6% of eligible employee compensation.

Our cost for contributions to the retirement savings plans was $1.0 million for fiscal years 2004 and 2003.

9. BUSINESS SEGMENTS

We have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business. Our other activities are insignificant. Our operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

10. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position 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 and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. However, energy markets are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Our 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. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Contracts that have been designated as normal purchase or normal sale under SFAS 133 are not considered derivatives and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on if 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. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses in the Statement of Income depending on the relevant facts and circumstances.

We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) and subsequently reclassify it to Revenues when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change.

Fair Value Hedging Strategies

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. The interest rate forward and swap transactions effectively modify exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify exposure to interest risk by converting a portion of floating-rate debt to a fixed rate.

We enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity. During 2004, we classified immaterial amounts into earnings as a result of hedge ineffectiveness related to cash flow hedging strategies.

Net gains from cash flow hedges in Accumulated Other Comprehensive Income (Loss) of approximately $0.8 million at December 31, 2004 are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is fourteen months.

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt are based on quoted market prices 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 significant financial instruments at December 31, 2004 and 2003 are summarized in the following tables.

	2004		2003	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	508,310	521,776	487,602	503,704

11. INCOME TAXES

The details of income taxes before extraordinary loss for the year ended December 31 as reported are as follows:

	2004	2003
	(in thousands)	
Charged (Credited) to Operating Expenses (net):		
Current	$ (3,789)	$ (7,009)
Deferred	14,925	21,183
Deferred Investment Tax Expense (Credits)	(1,233)	(1,168)
Total	9,903	13,006
Charged (Credited) to Nonoperating Income (net):		
Current	919	(2,213)
Deferred	(2,151)	(1,076)
Deferred Investment Tax Credits	-	(42)
Total	(1,232)	(3,331)
Total Income Tax as Reported	$ 8,671	$ 9,675

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported for the year ended December 31.

	2004	2003
	(in thousands)	
Net Income	$ 25,905	$ 32,330
Extraordinary Item	-	1,134
Income Taxes	8,671	9,675
Pretax Income	$ 34,576	$ 43,139
Income Tax on Pretax Income at Statutory Rate (35%)	$ 12,102	$ 15,099
Increase (Decrease) in Income Tax resulting from the following items:		
Depreciation	1,466	1,538
Allowance for Funds Used During Construction	(603)	(851)
Removal Costs	(1,497)	(735)
Investment Tax Credits (net)	(1,233)	(1,210)
State and Local Income Taxes	(197)	(58)
Other	(1,367)	(4,108)
Total Income Taxes as Reported	$ 8,671	$ 9,675
Effective Income Tax Rate	25.1 %	22.4 %

The following tables show the elements of our net deferred tax liability and the significant temporary differences at December 31:

	2004	2003
	(in thousands)	
Deferred Tax Assets	$ 39,511	$ 35,264
Deferred Tax Liabilities	(267,047)	(247,385)
Net Deferred Tax Liabilities	$ (227,536)	$ (212,121)
Property Related Temporary Differences	$ (169,452)	$ (151,404)
Amounts Due From Customers For Future Federal Income Taxes	(25,112)	(23,203)
Deferred State Income Taxes	(32,099)	(33,535)
Transition Regulatory Assets	-	-
Deferred Income Taxes on Other Comprehensive Loss	4,725	3,345
Deferred Fuel and Purchased Power	-	496
Accrued Pensions	(768)	-
Provision for Refund	-	-
All Other (Net)	(4,830)	(7,820)
Net Deferred Tax Liabilities	$ (227,536)	$ (212,121)

The Internal Revenue Service (IRS) and other taxing authorities routinely examine our tax returns. Management believes that we have filed tax returns with positions that may be challenged by these tax authorities. These positions relate to the timing and amount of income, deductions and the computation of the tax liability. We have settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. Returns for the years 2000 through 2003 are presently being audited by the IRS.

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. We accrue 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 results of operations.

We join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the PUHCA. These rules permit the allocation of 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, AEP Co., 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 consolidated group.

12. LEASES

Leases of property, plant and equipment are for periods up to 20 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 operating 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 for the year ended December 31 are as follows:

	2004	2003
	(in thousands)	
Lease Payments on Operating Leases	$ 1,416	$ 1,258
Amortization of Capital Leases	1,605	1,951
Interest on Capital Leases	258	148
Total Lease Rental Costs	$ 3,279	$ 3,357

Property, plant and equipment under capital leases and related obligations at December 31 are as follows:

	2004	2003
	(in thousands)	
Property, Plant and Equipment Under Capital Leases:		
Production	$ 797	$ 1,138
Distribution	-	-
Other	10,405	11,562
Total Property, Plant and Equipment	11,202	12,700
Accumulated Amortization	6,839	7,408
Net Property, Plant and Equipment Under Capital Leases	$ 4,363	$ 5,292
Obligations Under Capital Leases:		
Noncurrent Liability	$ 2,802	$ 3,549
Liability Due Within One Year	1,561	1,743
Total Obligations Under Capital Leases	$ 4,363	$ 5,292

Future minimum lease payments consisted of the following at December 31, 2004:

	Capital	Noncancelable Operating Leases
	(in thousands)	
2005	$ 1,854	$ 1,475
2006	1,195	1,150
2007	962	982
2008	519	741
2009	184	595
Later Years	169	1,792
Total Future Minimum Lease Payments	4,883	$ 6,735
Less Estimated Interest Element	520	
Estimated Present Value of Future Minimum Lease Payments	$ 4,363	

13. FINANCING ACTIVITIES

Dividend Restrictions

Under PUHCA, we can only pay dividends out of retained or current earnings.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet our short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2007 for short-term borrowings sufficient to fund the Utility Money Pool as well as its other requirements in an amount not to exceed $7.2 billion. Our Utility Money Pool activity and corresponding SEC authorized limits for the year ended December 31, 2004 are described in the following table:

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, 2004	SEC Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 44,749	$ 41,501	$ 13,580	$ 15,282	$ 16,127	$ 200,000

Our maximum, minimum and average interest rates for funds loaned to and borrowed from the Utility Money Pool during 2004 are summarized in the following table:

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
		(in percentages)			
1.92	0.91	2.24	0.89	1.59	1.61

As of December 31, 2004, AEP had credit facilities totaling $2.8 billion to support its commercial paper program. As of December 31, 2004, AEP's commercial paper outstanding related to the corporate borrowing program was $0. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper. On August 2, 2004, Moody's Investor Services placed AEP's ratings on positive outlook.

Our interest expense related to the Utility Money Pool is included in Interest on Debt to Associate Companies. We incurred interest expense for amounts borrowed from the Utility Money Pool of $65 thousand and $897 thousand in 2004 and 2003, respectively.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. Interest income earned from amounts advanced to the Utility Money Pool was $177 thousand in 2004. There was no interest income earned from amounts advanced to the Utility Money Pool in 2003.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement (expires on August 24, 2007) with banks and commercial paper conduits. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash.

Under the factoring arrangement, we sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for our receivables and administrative costs. The amount of factored accounts receivable and accrued unbilled revenues was $34.4 million and $30.4 million at December 31, 2004 and 2003, respectively.

We paid fees to AEP Credit for factoring customer accounts receivable of $2.6 million and $2.4 million in 2004 and 2003, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see in Note 13 "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit."

AEP System Power Pool

The AEP East companies are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, the AEP East companies have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power and gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. 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 including exchange traded futures and options and over-the-counter 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, the AEP Power Pool 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.

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East and West companies zone. 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). It 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 each zone.

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

Under the Interconnection Agreement, power generated that is not needed to serve our native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary. See Note 11 for a discussion of the marketing of such power.

Sales and Purchases to the Pool

The following table shows our revenues derived from sales to the pool and direct sales to our affiliates for years ended December 31, 2004 and 2003:

Related Party Revenues	2004	2003
	(in thousands)	
Sales to East System Pool	$ 36,032	$ 32,827
Sales to West System Pool	-	6
Direct Sales to East Affiliates	-	-
Direct Sales to West Affiliates	5,155	6,425
Other	403	550
Total Revenues	$ 41,590	$ 39,808

The following table shows our purchased power expense incurred from purchases from the pool and affiliates for the years ended December 31, 2004 and 2003:

Related Party Purchases	2004	2003
	(in thousands)	
Purchases from East System Pool	$ 68,072	$ 71,259
Direct Purchases from East Affiliates	72,475	70,249
Direct Purchases from West Affiliates	211	182
Total Purchases	$ 140,758	$ 141,690

The above summarized related party revenues and expenses are reported as Operating Revenues and Operation Expenses on the Statement of Income.

AEP System Transmission Pool

The AEP East companies are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), 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 "member-load-ratio."

Net credits allocated to us under the Transmission Agreement during the years ended December 31, 2004 and 2003 were $6.1 million and $5.6 million, respectively.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's East and West companies zones. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. 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 Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

Natural Gas Contracts with DETM

Effective October 31, 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 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. Our liabilities at December 31, 2004 and 2003 were $5.6 million and $7.3 million, respectively.

Fuel Agreement between OPCo and National Power Cooperative, Inc

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for a gas plant, which is owned by NPC. The plant went into service in July 2002 and the AEP East companies purchase 100% of the available generating capacity from the plant through December 2005. Our related purchases of gas managed by AEPES were $315,000 and $363,000 in 2004 and 2003, respectively.

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) for such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and us, and a unit power agreement between AEGCo and us, AEGCo sells to us 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. We have agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. Our unit power agreement was renegotiated and extended from December 31, 2004 to December 7, 2022.

I&M Barging and Other Services

I&M provides barging and other transportation services to us. We record costs paid to I&M for barging services as fuel expense or operation expense. The amount of expenses were $0.1 million and $0.1 million in 2004 and 2003, respectively.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and 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, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

15. LONG-TERM DEBT

	December 31, 2004	December 31, 2003
LONG-TERM DEBT:	(in thousands)	
Senior Unsecured Notes	$ 428,310	$ 427,602
Notes Payable - Affiliated	80,000	60,000
Long-term Debt Excluding Portion Due Within One Year	$ 508,310	$ 487,602

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

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	December 31, 2004	December 31, 2003
		(in thousands)	
6.910	2007 – October 1	$ 48,000	$ 48,000
6.450	2008 – November 10	30,000	30,000
5.500	2007 – July 1	125,000	125,000
4.310	2007 – November 12	80,400	80,400
4.370	2007 – December 12	69,564	69,564
5.625	2032 – December 31	75,000	75,000
Unamortized Discount		(268)	(362)
Interest Rate Hedge		614	-
Total		$ 428,310	$ 427,602

Notes Payable to Parent were as follows:

% Rate	Due	December 31, 2004 (in thousands)	December 31, 2003 (in thousands)
6.501	2006 – May 15	$ 60,000	$ 60,000
5.250	2015 – June 1	20,000	-
Total		$ 80,000	$ 60,000

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount (in thousands)
2005	$ -
2006	60,000
2007	322,964
2008	30,000
2009	-
Later Years	95,000
Total Principal Amount	507,964
Unamortized Discount	(268)
Interest Rate Hedge	614
Total	$ 508,310

16. SUPPLEMENTAL INFORMATION

Cash received for interest net of capitalized amounts was $28.4 million and $27.0 million and for income taxes was $3.2 million and $17.6 million in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $0.9 million in 2004. There were no noncash acquisitions under capital leases in 2003.

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.

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 Quarter/Year		(9,772,686)		
2	Preceding Quarter/Year Reclassification from Account 219 to Net Income				
3	Preceding Quarter/Year Changes in Fair Value		3,140,222		
4	Total (lines 2 and 3)		3,140,222		
5	Balance of Account 219 at End of Preceding Quarter/Year / Beginning of		(6,632,464)		
6	Current Quarter/Year Reclassifications from Account 219 to Net Income				
7	Current Quarter/Year Changes in Fair Value		(2,955,786)		
8	Total (lines 6 and 7)		(2,955,786)		
9	Balance of Account 219 at End of Current Quarter/Year		(9,588,250)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Power Generation] (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	424,669	(102,562)	(9,450,579)		
2		109,561	109,561		
3	(86,376)	74,777	3,128,623		
4	(86,376)	184,338	3,238,184	32,330,251	35,568,435
5	338,293	81,776	(6,212,395)		
6	(93,571)	(431,320)	(524,891)		
7		918,102	(2,037,684)		
8	(93,571)	486,782	(2,562,575)	25,904,692	23,342,117
9	244,722	568,558	(8,774,970)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 (f) 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)	1,310,143,711	1,310,143,711
4	Property Under Capital Leases	4,362,923	4,362,923
5	Plant Purchased or Sold		
6	Completed Construction not Classified	16,794,641	16,794,641
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,331,301,275	1,331,301,275
9	Leased to Others		
10	Held for Future Use	6,862,819	6,862,819
11	Construction Work in Progress	16,544,432	16,544,432
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,354,708,526	1,354,708,526
14	Accum Prov for Depr, Amort, & Depl	419,847,987	419,847,987
15	Net Utility Plant (13 less 14)	934,860,539	934,860,539
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	411,489,586	411,489,586
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	8,358,401	8,358,401
22	Total In Service (18 thru 21)	419,847,987	419,847,987
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	419,847,987	419,847,987

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
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					28
					29
					30
					31
					32
					33

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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		
3	(302) Franchises and Consents	52,919	
4	(303) Miscellaneous Intangible Plant	14,876,132	3,606,495
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	14,929,051	3,606,495
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,546	
9	(311) Structures and Improvements	35,593,179	630,676
10	(312) Boiler Plant Equipment	320,790,767	6,041,203
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	72,337,427	1,394,539
13	(315) Accessory Electric Equipment	13,741,735	4,907
14	(316) Misc. Power Plant Equipment	5,885,267	698,136
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	449,424,921	8,769,461
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		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	449,424,921	8,769,461
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	25,635,236	63,045
49	(352) Structures and Improvements	6,387,113	-48
50	(353) Station Equipment	120,544,904	3,307,719
51	(354) Towers and Fixtures	92,512,733	-148,377
52	(355) Poles and Fixtures	36,041,575	1,823,084
53	(356) Overhead Conductors and Devices	100,030,466	380,194
54	(357) Underground Conduit	11,590	
55	(358) Underground Conductors and Devices	106,066	
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)	381,269,683	5,425,617
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,940,781	199,846
61	(361) Structures and Improvements	3,835,651	395,784
62	(362) Station Equipment	40,917,861	1,425,859
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	123,330,237	4,606,829
65	(365) Overhead Conductors and Devices	95,111,036	5,364,176
66	(366) Underground Conduit	2,788,595	173,356
67	(367) Underground Conductors and Devices	4,707,295	811,825
68	(368) Line Transformers	82,653,943	2,607,713
69	(369) Services	29,717,370	2,034,573
70	(370) Meters	20,897,726	1,006,674
71	(371) Installations on Customer Premises	14,151,655	1,563,148
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	2,635,577	139,549
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	425,687,727	20,329,332
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	2,871,327	-7,247
78	(390) Structures and Improvements	29,482,547	143,886
79	(391) Office Furniture and Equipment	1,462,394	278,932
80	(392) Transportation Equipment	5,819	
81	(393) Stores Equipment	150,560	39,481
82	(394) Tools, Shop and Garage Equipment	1,650,404	64,391
83	(395) Laboratory Equipment	397,799	
84	(396) Power Operated Equipment	5,931	
85	(397) Communication Equipment	5,019,968	521,211
86	(398) Miscellaneous Equipment	503,264	81,420
87	SUBTOTAL (Enter Total of lines 77 thru 86)	41,550,013	1,122,074
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	41,550,013	1,122,074
91	TOTAL (Accounts 101 and 106)	1,312,861,395	39,252,979
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	1,312,861,395	39,252,979

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
					2
			52,919		3
1,211,678		123	17,271,072		4
1,211,678		123	17,323,991		5
					6
					7
			1,076,546		8
74,097			36,149,758		9
2,293,276			324,538,694		10
					11
692,983			73,038,983		12
4,041			13,742,601		13
64,449			6,518,954		14
					15
3,128,846			455,065,536		16
					17
					18
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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.
					44
					45
3,128,846			455,065,536		46
					47
			25,698,281		48
			6,387,065		49
699,507			123,153,116		50
			92,364,356		51
358,451			37,506,208		52
55,179			100,355,481		53
			11,590		54
			106,066		55
					56
					57
1,113,137			385,582,163		58
					59
1,195			5,139,432		60
370			4,231,065		61
325,880			42,017,840		62
					63
3,264,700		-123	124,672,243		64
1,048,651			99,426,561		65
2,052			2,959,899		66
37,052			5,482,068		67
1,076,234			84,185,422		68
511,999			31,239,944		69
832,607			21,071,793		70
115,921			15,598,882		71
					72
33,892			2,741,234		73
					74
7,250,553		-123	438,766,383		75
					76
1,233,430		-22,124	1,608,526		77
10,330,436			19,295,997		78
3,747			1,737,579		79
			5,819		80
779			189,262		81
3,477			1,711,318		82
3,405			394,394		83
			5,931		84
874,410			4,666,769		85
			584,684		86
12,449,684		-22,124	30,200,279		87
					88
					89
12,449,684		-22,124	30,200,279		90
25,153,898		-22,124	1,326,938,352		91
					92
					93
					94
25,153,898		-22,124	1,326,938,352		95

Schedule Page: 204 Line No.: 91 Column: c

ACCOUNT 106 - COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC

	Amounts Included in Column (c)
Intangible Plant	
303 - Misc Intangible Plant	3,377,725
Intangible Plant Subtotal:	3,377,725
Steam Generation Plant	
310 - Land and Land Rights	-
311 - Structures and Improvements	330,241
312 - Boiler Plant Equipment	(15,776,642)
314 - Turbogenerator Units	(7,311,237)
315 - Accessory Electric Equipment	1,652
316 - Misc Power Plant Equipment	-
Steam Generation Plant Subtotal:	(22,755,986)
Transmission Plant - Electric	
350 - Land and Land Rights	6,817
352 - Structures and Improvements	-
353 - Station Equipment	2,657,152
354 - Towers and Fixtures	-
355 - Poles and Fixtures	(412,804)
356 - Overhead Conductors and Devices	(434,178)
Transmission Plant - Electric Subtotal:	1,816,987
Distribution Plant - Electric	
360 - Land and Land Rights	(47,016)
361 - Structures and Improvements	-
362 - Station and Equipment	(385,719)
364 - Poles, Towers and Fixtures	(246,249)
365 - Overhead Conductors, Devices	343,257
366 - Underground Conduit	(13,997)
367 - Underground Conductors, Devices	403,779
368 - Line Transformers	(271,604)
369 - Services	(13,815)
370 - Meters	114,513
371 - Installs on Customer Premises	19,792
373 - Street Lighting, Signal System	(59,995)
Distribution Plant - Electric Subtotal:	(157,054)
General Plant	
389 - Land and Land Rights	(7,247)
390 - Structures and Improvements	138,178
391 - Office Furniture, Equipment	252,377
392 - Transportation Equipment	-
393 - Stores Equipment	-
394 - Tools, Shop, Garage Equipment	(40,556)

395 - Laboratory Equipment	-
397 - Communication Equipment	399,251
398 - Miscellaneous Equipment	-
General Plant Subtotal:	742,003
Grand Total:	(16,976,325)

Grand Total:

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
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45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	4 ITEMS OF PROPERTY HELD FOR FUTURE USE (EACH			
3	ITEM WITH AN ORIGINAL COST LESS THAN $150,000).			84,464
4				
5				
6				
7	CARRS PLANT SITE	08/17/82		6,778,355
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
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46				
47	Total			6,862,819

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Big Sandy Unit 2 SCR	3,173,228
2	Generation Production Plant Blanket	2,715,851
3	2005 KPCO Asset Improvement Blanket	2,263,930
4	Big Sandy Railcar Unloader Upgrade	1,401,507
5	Extension of Fly Ash Retention Dam	887,275
6	Beaver Creek-Harbert 138kV Coal Ste	752,748
7	KP/2004-2005 R/W Widening	623,194
8	Transmission Public Project Relocation Blanket	548,792
9	Distribution Public Project Relocation Blanket	436,345
10	Big Sandy 2 FGD Phase 1 Engineering	393,086
11	Generation Capitalized Software Blanket	371,537
12	Transmission System Improvement Blanket	317,797
13	Energy Delivery Customer Service Blanket	306,350
14	Big Sandy 2 FGD Landfill & Air Modeling	280,145
15	Big Sandy 1 - OFA, H2O Overlay	268,898
16	DAP H H Computer Replace-KyPCo	258,989
17	Distribution Line Transformer Blanket	180,424
18	KP 2004-2005 Targeted Ckt Rel	180,265
19	Distribution Capitalized Software Blanket	179,626
20	PRIOR 2002 Transmission Blanket	178,202
21	PRIOR 2002 Energy Delivery Distribution Blanket	114,394
22	KP TELECOM CAPITAL BLANKET-DIST	112,551
23	Substation Intrusion Detection	109,251
24	Other Projects Less Than $100,000	490,047
25		
26		
27		
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42		
43	TOTAL	16,544,432

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	395,041,900	395,041,900		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	35,339,258	35,339,258		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,858,878	3,858,878		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	39,198,136	39,198,136		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	23,942,221	23,942,221		
13	Cost of Removal	5,169,516	5,169,516		
14	Salvage (Credit)	6,361,290	6,361,290		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	22,750,447	22,750,447		
16	Other Debit or Cr. Items (Describe, details in footnote):	-3	-3		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	411,489,586	411,489,586		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	166,888,161	166,888,161		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	112,855,660	112,855,660		
26	Distribution	126,210,213	126,210,213		
27	General	5,535,552	5,535,552		
28	TOTAL (Enter Total of lines 20 thru 27)	411,489,586	411,489,586		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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				
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40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

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
				2
				3
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				10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)	9,240,156	6,404,680	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	240,961	145,892	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	749,061	698,338	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	4,845,284	4,928,593	Electric
8	Transmission Plant (Estimated)	15,478	171,690	Electric
9	Distribution Plant (Estimated)	11,617	45,494	Electric
10	Assigned to - Other (provide details in footnote)	23,484	7,765	Electric
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	5,644,924	5,851,880	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	15,126,041	12,402,452	

Schedule Page: 227 Line No.: 10 Column: c

General & Administrative items not directly related to generation, transmission, or distribution.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2005 No. (d)	2005 Amt. (e)
1	Balance-Beginning of Year	74,619.00	3,185,592	43,441.00	1,380,758
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	8,708,566.00		3,350.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Morgan Stanley Capitol Gr	3,604.00	682,958	1,083.00	217,304
10	US Gen New England, Inc			36.00	21,618
11	Lansing Brd of Water & Lt	141.00	37,393		
12	Jacksonville Energy			317.00	81,152
13	Chicago Climate Exchange	18,118.00	18,695	17,133.00	18,164
14	Other	14,389.00	2,247,181		
15	Total	36,252.00	2,986,227	18,569.00	338,238
16					
17	Relinquished During Year:				
18	Charges to Account 509	8,302,420.00	3,616,107		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Chicago Climate Exchange	7,616.00	227	6,708.00	7,012
23	Adjustments 2004	2,593.00	2,392	791.00	665
24	Ohio Power (Affiliated)	3,857.00	277,754		
25	Mirant Americas Energy	703.00	49,561		
26	Cincinnati Gas & Electric	4,307.00	309,095		
27	Other	1,763.00	94,553		
28	Total	20,839.00	733,582	7,499.00	7,677
29	Balance-End of Year	496,178.00	1,822,130	57,861.00	1,711,319
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		1,193,412		
33	Net Sales Proceeds (Other)		2,213,600		10,075
34	Gains		2,676,222		3,110
35	Losses		400		47
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	505.00		505.00	
37	Add: Withheld by EPA	101.00			
38	Deduct: Returned by EPA				
39	Cost of Sales	606.00			
40	Balance-End of Year			505.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		137,979		
45	Gains		137,979		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

2006		2007		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
50,732.00	2,671,605	44,125.00	1,082,446	934,501.00	2,619,603	1,147,418.00	10,940,004	1
								2
								3
3,350.00		979.00		36,903.00		8,753,148.00		4
								5
								6
								7
								8
1,083.00	217,304	1,083.00	217,304	1,083.00	217,304	7,936.00	1,552,174	9
146.00	86,943	146.00	86,213	436.00	199,688	764.00	394,462	10
528.00	140,026	422.00	111,914	352.00	93,350	1,443.00	382,683	11
528.00	158,062	598.00	183,576	1,408.00	444,427	2,851.00	867,217	12
10,989.00	13,919					46,240.00	50,778	13
				8,789.00	1,124,996	23,178.00	3,372,177	14
13,274.00	616,254	2,249.00	599,007	12,068.00	2,079,765	82,412.00	6,619,491	15
								16
								17
						8,302,420.00	3,616,107	18
								19
								20
								21
2,606.00	2,994					16,930.00	10,233	22
						3,384.00	3,057	23
						3,857.00	277,754	24
						703.00	49,561	25
						4,307.00	309,095	26
						1,763.00	94,553	27
2,606.00	2,994					30,944.00	744,253	28
64,750.00	3,284,865	47,353.00	1,681,453	983,472.00	4,699,368	1,649,614.00	13,199,135	29
								30
								31
							1,193,412	32
	3,533						2,227,208	33
	543						2,679,875	34
	4						451	35
504.00		503.00		24,496.00		26,513.00		36
						101.00		37
								38
				506.00		1,112.00		39
504.00		503.00		23,990.00		25,502.00		40
								41
								42
								43
					64,653		202,632	44
					64,653		202,632	45
								46

Schedule Page: 228 Line No.: 14 Column: a

In 2003 AEP joined the Chicago Climate Exchange (CCX) which is a self regulatory exchange that administers the world's first multi-national marketplace for reducing and trading greenhouse gas emissions. Account 1581 contains sulfur dioxide (SO2), carbon dioxide (CO2), and nitrous oxide (NOx) allowances. The SO2 and NOx allowances are reported in tons. The CO2 allowances are reported in metric tons.

Purchased/Transfers: Other

	Current Year	
	Number	Amount
Arizona Public Service	361	73,644
Dominion Energy Marketing, Inc.	2,459	632,764
EPA	5,276	1,464,196
Westar Energy	361	76,577
Ohio Power (Affiliated)	5,932	-
	14,389	2,247,181

	Future Years	
	Number	Amount
EPA	8,789	1,124,990
Adjustment 2004	-	6
	8,789	1,124,996

Schedule Page: 228 Line No.: 27 Column: a

Cost if Sales /Transfers: Other

	Current Year	
	Number	Amount
AEP System Pool (Affiliated)	1,313	94,553
Dynegy Inc.	100	-
Solutia, Inc.	100	-
Cogentrix Energy, Inc	200	-
Dominion Energy Marketing, Inc.	50	-
	1,763	94,553

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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						
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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						
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45						
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47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 $50,000 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	Merger Costs	2,388,053	14,669	407	606,768	1,795,954
2	Amortz period: Aug 2000-July 2008					
3						
4	Allowances	10,502		Various	10,502	
5						
6	SFAS 109 Deferred FIT	74,136,647	5,606,735	Various	1,406,293	78,337,089
7						
8	SFAS 109 Deferred SIT	33,535,000	2,605,000	283	4,041,000	32,099,000
9						
10	SFAS 112 Post Employment Benefit	5,319,380	260,200	228	1,009,053	4,570,527
11						
12	Depreciation Expenses - Hanging Rock/					
13	Jefferson 765 KV Line	966,312		406	33,408	932,904
14	Amortz period: Dec 1984-Nov 2032					
15						
16	Post In-Service AFUDC Hanging Rock/					
17	Jefferson 765 KV line	150,601		406	5,208	145,393
18	Amortz period: Dec 1984-Nov 2032					
19						
20	Deferred DSM Expenses	2,805,333	1,644,339	Various	1,045,238	3,404,434
21						
22	Unrealized Loss on Forward Committments	1,242,791	42,639,257	Various	41,194,297	2,687,751
23						
24						
25						
26						
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43						
44	TOTAL	120,554,619	52,770,200		49,351,767	123,973,052

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 $50,000, 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	Emission Allowances	23,554	6,825,569	Various	6,840,395	8,728
2						
3	Deferred Expenses	441,156	1,615,055	Various	2,056,211	
4						
5	Deferred Property Tax	6,847,200	7,035,500	408	6,847,200	7,035,500
6						
7	Agency Fees - Factored A/R	606,892	6,616,620	Various	6,535,828	687,684
8						
9	BridgeCo RTO Funding	429,852	207	234	5,398	424,661
10						
11	BridgeCo RTO Deferred Expenses	239,096	4,671	234	686	243,081
12						
13	Labor Accrual - Balance Sheet	77,722	3,743,152	242	3,633,248	187,626
14						
15	PJM Integration & Payments	946,426	475,944	234	31,094	1,391,276
16						
17	Carrying Chgs Deferred RTO Cost	182,125	165,332			347,457
18						
19	NonTradition Option Premiums		5,059,224	Various	4,225,195	834,029
20						
21	Misc Items	-162	16,780	Various	14,681	1,937
22						
23						
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46						
47	Misc. Work in Progress	282,415				247,249
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,076,276				11,409,228

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	Interest Expense Capitalized	4,870,336	4,794,989
3	Contribution-in-Aid of Construction	1,908,910	2,177,274
4	Mark-To-Market	2,980,761	3,703,750
5	Deferred Fuel	884,537	2,775,957
6	Accrued SFAS 112 Post Employment Benefits	1,861,780	1,662,302
7	Other	1,329,654	1,502,258
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,835,978	16,616,530
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	21,428,293	22,894,600
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	35,264,271	39,511,130

Notes

Page 234 Line 17	Beginning of Year	End of Year
Non-Utility Items 190.2	344,207	950,267
SFAS 109	17,266,586	15,892,904
SFAS 133	3,817,500	6,051,429
Total	$21,428,293	$22,894,600

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	2,000,000	50.00	
2				
3				
4				
5				
6				
7				
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10				
11				
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13				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,009,000	50,450,000					1
						2
						3
						4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	
2	Contributions by Parent Company	208,750,000
3		
4		
5	SUBTOTAL - Account 208	208,750,000
6		
7	Account 209 - Reduction in Par or Stated Value of Capital Stock	
8		
9	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
10		
11	Account 211 - Miscellaneous Paid-In-Capital	
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39		
40	TOTAL	208,750,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

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	SUBTOTAL ACCOUNT 221 - BONDS		
4			
5			
6	ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
7	Global Note Payable to Parent Company (American Electric Power Company) - 5.250%	20,000,000	
8			
9	Global Note Payable to Parent Company (American Electric Power Company) - 6.501%	60,000,000	
10	SUBTOTAL ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES	80,000,000	
11			
12			
13	ACCOUNT 224 - OTHER LONG-TERM DEBT		
14	Senior Unsecured Notes - 4.315%, Series B	80,400,000	2,056,614
15			
16	Senior Unsecured Notes - 4.368% Series C	69,564,000	1,975,083
17			
18	Senior Unsecured Notes - 5.500%, Series A	125,000,000	858,150
19			227,500 D
20	Senior Unsecured Notes - 5.500%, Series A - FAS 133 Fair Value Hedge		
21			
22	Senior Unsecured Notes - 5.625%, Series D	75,000,000	736,575
23			656,250 D
24			
25	Senior Unsecured Notes - 6.450%, Series A	30,000,000	51,517
26			187,500 D
27			
28	Senior Unsecured Notes - 6.910%	48,000,000	63,413
29			300,000 D
30			
31	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT	427,964,000	7,112,602
32			
33	TOTAL	507,964,000	7,112,602

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
02/05/2004	06/01/2015			20,000,000	950,833	7
						8
05/10/2001	05/15/2006			60,000,000	3,900,600	9
				80,000,000	4,851,433	10
						11
						12
						13
11/12/2002	11/12/2007	11/12/2002	11/12/2007	80,400,000	3,469,099	14
						15
12/12/2002	12/12/2007	12/12/2002	12/12/2007	69,564,000	3,038,556	16
						17
06/28/2002	07/01/2007	06/28/2002	07/01/2007	125,000,000	6,365,454	18
		06/28/2002	07/01/2007			19
07/01/2004	07/01/2007			614,427		20
						21
06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750	22
		06/13/2003	12/01/2032			23
						24
11/10/1998	11/10/2008	11/10/1998	11/10/2008	30,000,000	1,935,000	25
		11/10/1998	11/10/2008			26
						27
10/01/1997	10/01/2007	10/01/1997	10/01/2007	48,000,000	3,316,800	28
		10/01/1997	10/01/2007			29
						30
				428,578,427	22,343,659	31
						32
				508,578,427	27,195,092	33

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ISSUANCE - GLOBAL NOTES:
Debt: 5.250% Global Note Payable to Parent Company (American Electric Power Company)
Principal Amount: $20,000,000
Date of Issuance: 02/05/2004
Date of Maturity: 06/01/2015
Authorization: Kentucky Public Service Commissin Case No. 2002-00324

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ACCOUNT 427 INTEREST ON LONG-TERM DEBT:	
Long-Term Debt:	
Contra Account 237 Interest Accrued	$27,195,092
Cash Flow Hedge - Interest Rate:	
Contra Account 219 Accum Oth Comprehensive Income	-93,571
Contra Account 283 Accum Deferred Income Tax	-50,384
Total Account 427 Interest On Long-Term Debt	$27,051,137
ACCOUNT 430 INTEREST ON DEBT TO ASSOCIATED COMPANIES:	
Corporate Borrowing Program:	
Contra Account 233 Notes Payable to Assoc Cos	$ 306,065
Total Account 430 Interest On Debt to Associated Companies	$ 306,065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)	25,904,692
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	9,990,246
28	Show Computation of Tax:	
29	See Page 261 Footnote 1 and 2 for Computation of Tax	
30		
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Schedule Page: 261 Line No.: 29 Column: b

		In (000's)
Net Income for the year per Page 117		25,905
Federal Income Taxes		8,974
Pretax Book Income		34,879
Increase (Decrease) in Taxable Income resulting from:		
Allowance for Funds Used During Construction and Other Differences Between Items Capitalized for Books and Expensed for Tax		(9)
Corporate Owned Life Insurance (COLI)		(67)
Capitalized Relocation Costs		(12,174)
Deferred Fuel Costs (Net)		1,164
Demand Side Management (Net)		(599)
Emission Allowances (Net)		(2,169)
Excess Tax Vs Book Depreciation		(11,874)
Mark-to-Market		3,114
Merger Costs		602
Pension Expenses (Net)		119
RTO Expenses and Carrying Charges		(508)
Removal Costs - ACRS		(4,277)
Repair Allowance		(300)
Self Insurance - Book Reserve		(519)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)		651
Tax Accruals and Deferrals		561
Trading Credit Risk		(855)
Tax Vs. Book Gain/Loss		2,073
Other (Net)		178
Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		9,990
		=======
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		3,499
Adjustment due to System Consolidation	(a)	(100)
Tax Contingency Reserve Adjustment		1,195
Estimated Tax Currently Payable	(b)	4,594
Adjustments of Prior Year's Accruals (Net)		(7,161)
Estimated Current Federal Income Taxes (Net)		(2,567)
		========

(a) Represents the allocation of the estimated current year net operating tax loss of American Electric Power Company, Inc. in accordance with Rule 45(c) of the Public Utility Holding Company Act of 1935.

(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 is in accordance with Securities and Exchange Commission (SEC) rules under the Public Utility Holding

Company Act of 1935. These rules permit the allocation of the benefit of current tax losses and investment tax credits to the System companies giving rise to them in determining taxes currently payable. 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 2004 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed in September 2005. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until October 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	-136,078		-2,571,795	-4,714,897	
3	FICA			2,045,323	2,045,323	
4	Unemployment	11		23,126	22,488	
5						
6						
7						
8	STATE OF KENTUCKY					
9	Income 2003 & Prior	374,268		-1,204,600	-1,732,332	
10	2004			817,700	2,250,000	
11						
12	License Fee - 2004			100	100	
13						
14	KY State Unemployment	-64		13,127	12,777	
15	PUBLIC SER COMM'S-2003		263,827	263,827		
16	PUBLIC SER COMM'S-2004			252,210	504,415	
17						
18	SALES & USE TAX - 2003	20,128		-134	19,994	
19	SALES & USE TAX - 2004			289,657	259,558	
20	REAL & PERS PROP-2002	279,292		96,721	374,023	
21	REAL & PERS PROP-2003	6,847,200		686	6,334,510	
22	REAL & PERS PROP-2004			7,036,385	885	
23	PERS PROP LEASED-2003	-503		7,487	6,984	
24	PERS PROP LEASED-2004			175,022	38,502	
25	REAL PROP LEASED-2004			11,554	15,164	
26						
27	STATE OF WEST VIRGINIA					
28	Income-2003 & Prior	-38,245		2,651	-35,594	
29	2004			6,730	12,294	
30						
31	Franchise - 2003	10,103		13,933	24,036	
32	2004			9,600	24,854	
33						
34	License Fee - 2004			275	275	
35						
36	WV State Unemployment	36		120	88	
37						
38	REAL & PERS PROP2003			2,949	2,949	
39						
40	LEASED PROP - 2003			355	355	
41	TOTAL	7,329,064	263,827	7,456,365	5,525,628	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	SALES & USE TAX - 2003	53		-53		
2	SALES & USE TAX -2004			2,400		
3						
4	STATE OF VIRGINIA					
5	VA State Unemployment	32			32	
6						
7	STATE OF OHIO					
8	Income 2003	16,900		-858	16,042	
9	2004			75,585		
10						
11	Franchise 2004	-44,069		80,880	36,811	
12						
13	OTHER:					
14	REAL/PERS PROP-LA-2004				590	
15	PERS PROP LSED-OH-2003			3,221	3,221	
16	PERS PROP LSED-OH-2004			2,181	2,181	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	7,329,064	263,827	7,456,365	5,525,628	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
2,007,024		-3,485,726			913,931	2
		1,359,750			685,573	3
649		9,528			13,598	4
						5
						6
						7
						8
902,000		-1,204,600				9
-1,432,300		817,700				10
						11
		100				12
						13
286		9,359			3,768	14
		263,827				15
	252,205	252,210				16
						17
					-134	18
30,099		57			289,600	19
1,990		96,721				20
513,376		6,847,886			-6,847,200	21
7,035,500		885			7,035,500	22
		7,487				23
136,520		177,204			-2,182	24
-3,610		11,554				25
						26
						27
		2,651				28
-5,564		6,730				29
						30
		13,933				31
-15,254		9,600				32
						33
		275				34
						35
68		85			35	36
						37
		2,949				38
						39
		355				40
9,248,179	252,205	5,356,127			2,100,238	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)	
					-53	1
2,400					2,400	2
						3
						4
						5
						6
						7
		-858				8
75,585		75,585				9
						10
		80,880				11
						12
						13
-590						14
					3,221	15
					2,181	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
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						31
						32
						33
						34
						35
						36
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						39
						40
9,248,179	252,205	5,356,127			2,100,238	41

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year 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%	355,016			411.4	140,496	-938
4	7%						
5	10%	7,599,760			411.4	1,028,364	-63,253
6							
7							
8	TOTAL	7,954,776				1,168,860	-64,191
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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
213,582	Various		3
			4
6,508,143	Various		5
			6
			7
6,721,725			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
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			46
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			48

Schedule Page: 266 Line No.: 3 Column: g

Adjustment of Prior Year's Federal Income Tax Return (938)

Schedule Page: 266 Line No.: 5 Column: g

Adjustment of Prior Year's Federal Income Tax Return (63,253)

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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 $10,000, 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	Rents - Pole Contacts	67,407	454, 172	477,846	478,213	67,774
2						
3	Allowances	4,275	Various	2,447,446	2,443,769	598
4						
5	Deferred Gain - Affiliated	191,027	108	1,789		189,238
6	AEP Communication Leases					
7						
8	Deferred Revenue				207,367	207,367
9						
10	RTO Carrying Charges	103,025			100,787	203,812
11						
12	Unidentified Cash Receipts				6,669	6,669
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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42						
43						
44						
45						
46						
47	TOTAL	365,734		2,927,081	3,236,805	675,458

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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		19,268,201	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)		19,268,201	
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)		19,268,201	
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						19,268,201	4
							5
							6
							7
						19,268,201	8
							9
							10
							11
							12
							13
							14
							15
							16
						19,268,201	17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	115,095,820	13,662,326	18,401,126
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	115,095,820	13,662,326	18,401,126
6	SFAS 109	45,874,508		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	160,970,328	13,662,326	18,401,126
10	Classification of TOTAL			
11	Federal Income Tax	160,970,328	13,662,326	18,401,126
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
						110,357,020	2
							3
							4
						110,357,020	5
				182/254	3,115,280	48,989,788	6
							7
							8
					3,115,280	159,346,808	9
							10
					3,115,280	159,346,808	11
							12
							13

NOTES (Continued)

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	388,225	3,111,378	1,627,272
4	Market to Market	2,435,616	5,039,405	3,904,749
5	Capitalized Software - Book	4,026,896	197,099	558,201
6	Demand Side Management	981,708	274,744	65,059
7	Reg Assets	1,861,780	91,070	353,169
8	Other	1,330,630	2,357,169	1,381,695
9	TOTAL Electric (Total of lines 3 thru 8)	11,024,855	11,070,865	7,890,145
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	75,390,221		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	86,415,076	11,070,865	7,890,145
20	Classification of TOTAL			
21	Federal Income Tax	52,880,076	11,070,865	7,890,145
22	State Income Tax	33,535,000		
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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
						1,872,331	3
						3,570,272	4
						3,665,794	5
						1,191,393	6
						1,599,681	7
		190	3,779			2,302,325	8
			3,779			14,201,796	9
							10
							11
							12
							13
							14
							15
							16
							17
1,672,083	3,217,610	Various	1,436,000	Various	1,821,387	74,230,081	18
1,672,083	3,217,610		1,439,779		1,821,387	88,431,877	19
							20
1,672,083	3,217,610		3,779		1,821,387	56,332,877	21
			1,436,000			32,099,000	22
							23

NOTES (Continued)

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

Page 276 Line 18 - Other

	Beginning Balance	Ending Balance
Non-Utility	3,697,533	2,152,005
SFAS 109	71,220,324	70,751,631
SFAS 133	472,364	1,326,445
Total	75,390,221	74,230,081

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 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	Deferred Fuel Expense	1,418,030	501	61,810,109	62,973,862	2,581,783
2						
3	SFAS 109 Deferred FIT	7,843,401	Various	1,255,881	55	6,587,575
4						
5	Unrealized Gain on Forward Commitments	9,173,641	Various	145,527,825	149,394,820	13,040,636
6						
7						
8						
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37						
38						
39						
40						
41	TOTAL	18,435,072		208,593,815	212,368,737	22,209,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

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	128,982,113	120,000,845
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	75,584,276	68,904,706
5	Large (or Ind.) (See Instr. 4)	109,766,554	94,566,775
6	(444) Public Street and Highway Lighting	1,009,595	925,752
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	315,342,538	284,398,078
11	(447) Sales for Resale	110,411,723	112,747,656
12	TOTAL Sales of Electricity	425,754,261	397,145,734
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	425,754,261	397,145,734
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,413,521	1,436,904
17	(451) Miscellaneous Service Revenues	292,627	48,142
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,065,291	3,485,714
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	14,961,788	14,354,051
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	19,733,227	19,324,811
27	TOTAL Electric Operating Revenues	445,487,488	416,470,545

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
2,411,361	2,356,514	144,434	144,487	2
				3
1,373,092	1,311,942	28,289	27,390	4
3,180,997	2,930,209	1,466	1,463	5
11,144	10,559	442	448	6
				7
				8
				9
6,976,594	6,609,224	174,631	173,788	10
4,823,490	5,166,472	120	121	11
11,800,084	11,775,696	174,751	173,909	12
				13
11,800,084	11,775,696	174,751	173,909	14

Line 12, column (b) includes $ 3,907,336 of unbilled revenues.

Line 12, column (d) includes 21,193 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 Sales					
2	Residential Service	2,376,987	124,017,665	144,236	16,480	0.0522
3	Res Svc Load Mgmt TOD	5,925	238,092	198	29,924	0.0402
4	Small General Service	6	290			0.0483
5	Medium General Service	8	495			0.0619
6	All Outdoor Lighting	26,013	3,087,193			0.1187
7	Unbilled	2,422	1,638,378			0.6765
8	Total Residential	2,411,361	128,982,113	144,434	16,695	0.0535
9						
10	442 Commercial Sales					
11	Small General Service	80,409	6,443,917	17,244	4,663	0.0801
12	Medium General Service	559,342	34,405,405	10,292	54,347	0.0615
13	Medium General Service TOD	1,970	106,470	70	28,143	0.0540
14	Large General Service	556,373	26,608,440	643	865,277	0.0478
15	Quantity Power	145,756	5,128,207	17	8,573,882	0.0352
16	Street Lighting	136	15,841	1	136,000	0.1165
17	Municipal Waterworks	7,498	352,591	22	340,818	0.0470
18	All Outdoor Lighting	13,513	1,374,282			0.1017
19	Unbilled	8,095	1,149,123			0.1420
20	Total Commercial	1,373,092	75,584,276	28,289	48,538	0.0550
21						
22	442 Industrial Sales					
23	Small General Service	2,137	191,865	587	3,641	0.0898
24	Medium General Service	42,778	2,550,459	591	72,382	0.0596
25	Large General Service	251,555	12,159,245	206	1,221,141	0.0483
26	Quantity Power	763,005	28,742,770	68	11,220,662	0.0377
27	Commerical & Industrial TOD	2,110,058	64,931,040	14	150,718,429	0.0308
28	All Outdoor Lighting	802	74,129			0.0924
29	Unbilled	10,662	1,117,046			0.1048
30	Total Industrial	3,180,997	109,766,554	1,466	2,169,848	0.0345
31						
32	444 Public Street Lighting					
33	Small General Service	1,845	145,810	368	5,014	0.0790
34	Medium General Service	1,037	61,794	21	49,381	0.0596
35	Street Lighting	8,169	785,916	53	154,132	0.0962
36	All Outdoor Lighting	79	13,286			0.1682
37	Unbilled	14	2,789			0.1992
38	Total Public Street Lighting	11,144	1,009,595	442	25,213	0.0906
39						
40	Instruction 5. (See Note)					
41	TOTAL Billed	6,955,401	311,435,202	174,631	39,829	0.0448
42	Total Unbilled Rev.(See Instr. 6)	21,193	3,907,336	0	0	0.1844
43	TOTAL	6,976,594	315,342,538	174,631	39,950	0.0452

Schedule Page: 304 Line No.: 6 Column: d

Per Instruction #3

Outdoor lighting customers served by more than one rate schedule:

Residential	40,130
Commercial	6,810
Industrial	294
Public Street & Highway	33
Total	47,267

Schedule Page: 304 Line No.: 18 Column: d

Schedule Page: 304 Line No.: 28 Column: d

Schedule Page: 304 Line No.: 36 Column: d

Schedule Page: 304 Line No.: 40 Column: a

440 Residential		Fuel Clause
	Residential Service	1,563,210
	Res Svc Load Mgmt TOD	3,023
	Small General Service	(9)
	Medium General Service	(9)
	All Outdoor Lighting	24,780
	Unbilled	1,598,993
Total		3,189,988
442 Commercial		
	Small General Service	55,798
	Medium General Service	439,383
	Medium General Service TOD	1,310
	Large General Service	469,192
	Quantity Power	135,687
	Street Lighting	82
	Municipal Waterworks	5,755
	All Outdoor Lighting	13,295
	Unbilled	805,464
Total		1,925,966
442 Industrial		
	Small General Service	1,433
	Medium General Service	28,724
	Large General Service	200,194
	Quantity Power	675,318
	Commercial & Industrial TOD	2,043,079
	All Outdoor Lighting	754
	Unbilled	707,276
Total		3,656,778
444 Public Street Lighting		
	Small General Service	1,463
	Medium General Service	1,044
	Street Lighting	7,897
	All Outdoor Lighting	77
	Unbilled	2,076
Total		12,557

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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	Hamilton	RQ	OPCO 96			
2	Olivehill	RQ	KPCO 13			
3	Vanceburg	RQ	KPCO 18			
4						
5	City of Dowagiac, MI	IF	Note 1			
6	Cleveland Public Power	IF	Note 1			
7	East KY Power Co-Op Power Mktg	IF	KPCO 14			
8	Monongahela Power Company	IF	Note 1			
9	United Light & Power Company	IF	Note 1			
10	Wisconsin Public Service	IF	Note 1			
11	Wolverine Power Supply Coop	IF	Note 1			
12						
13	American Municipal Power-Ohio	LF	OPCO 74			
14	City of Radford	LF	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Sturgis	LF	Note 1			
2	NC Electric Membership Corp.	LF	Note 1			
3	OMEG	LF	Note 1			
4	Wabash Valley Power Assn Inc.	LF	Note 1			
5						
6	Carolina Power & Light	LU	Note 1			
7						
8	Hoosier Power Market	SF	Note 1			
9						
10	ABN AMRO, Inc.	OS	Note 1			
11	AEP Texas Central Company	OS	Note 1,2			
12	AEP Texas North Company	OS	Note 1,2			
13	AEP Utilities, Inc.	OS	Note 1,2			
14	Allegheny Energy Supply Co 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
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SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Allegheny Power GM	OS	Note 1			
2	ALLETE, Inc. dba Minnesota Pwr	OS	Note 1			
3	Alliant Energy	OS	Note 1			
4	Amerada Hess Corporation	OS	Note 1			
5	Ameren Energy Inc.	OS	Note 1			
6	Ameren Energy Marketing	OS	Note 1			
7	Ameren Services Company	OS	IMPCO 67			
8	American Electric Power Service Corp	OS	Note 1,2			
9	American Municipal Power-Ohio	OS	Note 1			
10	Aquila Merchant Services, Inc	OS	Note 1			
11	Arizona Public Svc	OS	Note 1			
12	Associated Elect Cooperative	OS	Note 1			
13	Austin Energy	OS	Note 1			
14	B.P. Energy Company	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447)

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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	Baltimore Gas & Electric	OS	Note 1			
2	Bank of America, N.A	OS	Note 1			
3	BNP Paribas Commodity Futures	OS	Note 1			
4	BP AMOCO	OS	Note 1			
5	Brascan Energy Marketing, Inc	OS	Note 1			
6	Brazos Electric Power Co-op	OS	Note 1			
7	Buckeye Rural Electric Admin	OS	Note 1			
8	Calpine Power Service Company	OS	Note 1			
9	Cargill - Alliant	OS	Note 1			
10	Carolina Power & Light	OS	Note 1			
11	Central Illinois	OS	Note 1			
12	Chevron Texaco	OS	Note 1			
13	Chevron USA Inc	OS	Note 1			
14	Cincinnati Gas & Electric Co	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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	Cinergy Marketing & Trading, L	OS	Note 1			
2	Citadel Energy Opportunity Ltd	OS	Note 1			
3	Citadel Energy Products LLC	OS	Note 1			
4	Citadel Equity Fund Ltd.	OS	Note 1			
5	City of Bryan Texas Utility	OS	Note 1			
6	City of Burbank	OS	Note 1			
7	City of Holland	OS	Note 1			
8	City of New Martinsville	OS	Note 1			
9	City of Philippi, West Virginia	OS	Note 1			
10	City of Sturgis	OS	Note 1			
11	Cleco Utility Group LLC	OS	Note 1			
12	Cleveland Public Power	OS	Note 1			
13	CMS Marketing Svcs and Trading	OS	Note 1			
14	ComEd Wholesale Marketing	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
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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	Conectiv Energy Supply Inc.	OS	Note 1			
2	ConEd Energy	OS	Note 1			
3	Conoco Inc.	OS	Note 1			
4	Constellation Power Source	OS	Note 1			
5	Consumers Energy Traders	OS	Note 1			
6	Cook Inlet Energy Supply LP	OS	Note 1			
7	Coral Energy Holding L.P.	OS	Note 1			
8	Coral Power LLC	OS	Note 1			
9	DC Energy, LLC	OS	Note 1			
10	Detroit Edison Merch	OS	Note 1			
11	Direct Energy, LP	OS	Note 1			
12	Dominion Equipment Inc	OS	Note 1			
13	Dominion Retail Inc	OS	Note 1			
14	Dow Pipeline	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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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.
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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	DP&L Power Services	OS	Note 1			
2	DTE Energy Trading Inc.	OS	Note 1			
3	Duke Energy Trading	OS	Note 1			
4	Duke Power Company	OS	APCO 18			
5	Duquesne Light Company	OS	Note 1			
6	Duquesne Power, L.P.	OS	Note 1			
7	Dynegy Marketing & Trade	OS	Note 1			
8	Dynegy Power Marketing Inc.	OS	Note 1			
9	East KY Power Co-Op Power Mktg	OS	KPCO 14			
10	Edison Mission Mktg & Trading	OS	Note 1			
11	El Paso Marketing, L.P.	OS	Note 1			
12	El Paso Merchant Energy L.P.	OS	Note 1			
13	Energy USA - TPC Corp	OS	Note 1			
14	Eng Mktg, div of Amerada Hess	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	Engage Energy America LLC	OS	Note 1			
2	Enmax Energy Marketing Inc	OS	Note 1			
3	Entergy - Koch Trading LP	OS	Note 1			
4	Entergy Power Serv	OS	Note 1			
5	Entergy Solutions Supply, Ltd.	OS	Note 1			
6	Exelon Generation - Power Team	OS	Note 1			
7	FirstEnergy Trading Services	OS	Note 1			
8	Florida Power & Light	OS	Note 1			
9	Florida Power Corporation	OS	Note 1			
10	FPL Energy Power MarketingInc	OS	Note 1			
11	Georgia Transmission Corporation	OS	Note 1			
12	GPU Energy	OS	Note 1			
13	Grand River Authority	OS	Note 1			
14	Harrison Rural Electrification	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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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	Hess Energy Trading Company, L	OS	Note 1			
2	HETC	OS	Note 1			
3	Hoosier Power Market	OS	Note 1			
4	HQ Energy Services US Inc.	OS	Note 1			
5	Indiana Municipal Power Agency	OS	IMPCO 74			
6	Indianapolis Power & Light Co	OS	IMPCO 21			
7	Interstate Gas Supply, Inc.	OS	Note 1			
8	J ARON & Company	OS	Note 1			
9	Kansas City Power & Light Co	OS	Note 1			
10	LG&E Energy Marketing, Inc.	OS	Note 1			
11	LG&E Utilities Power Sales	OS	Note 1			
12	Louis Dreyfus Energy Serv LP	OS	Note 1			
13	Lower Colorado River Authority	OS	Note 1			
14	Merrill Lynch Capital Svcs.	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	Merrill Lynch Commodities, Inc	OS	Note 1			
2	Metropolitan Edison Company	OS	Note 1			
3	Michigan Public Power Agency	OS	Note 1			
4	Michigan South Cent Pwr Agency	OS	Note 1			
5	MidAmerican Energy	OS	Note 1			
6	Midwest ISO	OS	Note 1			
7	MIECO Inc.	OS	Note 1			
8	Mirant Americas Energy Mktg LP	OS	Note 1			
9	Monongahela Power Company	OS	Note 1			
10	Morgan Stanley Capt.	OS	Note 1			
11	NC Electric Membership Corp.	OS	Note 1			
12	New York ISO	OS	Note 1			
13	New York Mercantile Exchange	OS	Note 1			
14	NIPSCO Energy Management	OS	IMPCO 22			
	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	NSP Energy Marketing	OS	Note 1			
2	Occidental Power Services, Inc.	OS	Note 1			
3	Ogelthorpe Power Corporation	OS	Note 1			
4	Old Dominion Elec.	OS	Note 1			
5	ONEOK Power Marketing	OS	Note 1			
6	Ontario Hydro	OS	Note 1			
7	Ontario Power Generation Inc.	OS	Note 1			
8	OPPD Energy Marketing	OS	Note 1			
9	Ormet Primary Aluminum Corp	OS	Note 1			
10	OVEC Power Scheduling	OS	Note 1			
11	Pacificorp Power Marketing	OS	Note 1			
12	Paribas	OS	Note 1			
13	Pennsylvania Electric Company	OS	Note 1			
14	Pennsylvania Power & Light	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	PEPCO Services Inc.	OS	Note 1			
2	PJM Interconnection	OS	Note 1			
3	Portland General Electric	OS	Note 1			
4	Powerex	OS	Note 1			
5	PP&L Energy Plus Co.	OS	Note 1			
6	PPL Gas Utilities Corp	OS	Note 1			
7	Progress Ventures, Inc.	OS	Note 1			
8	PSEG Energy Resources & Trade	OS	Note 1			
9	Public Service Co of Colorado	OS	Note 1			
10	Public Service Co of OK	OS	Note 1,2			
11	Public Svc Co of New Mexico	OS	Note 1			
12	Rainbow Energy Marketing	OS	Note 1			
13	REFCO Inc.	OS	Note 1			
14	Reliant Energy Serv.	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sched 9-1 Control Area Admin	OS	Note 1			
2	Sempra Energy Trading	OS	Note 1			
3	Sierra Pacific Power	OS	Note 1			
4	SIGE Power Marketing	OS	Note 1			
5	Sigeco/Hoosier (Sigehoo)	OS	Note 1			
6	Silicon Valley Power	OS	Note 1			
7	South Carolina Electric & Gas	OS	Note 1			
8	South Texas Electric Coop	OS	Note 1			
9	Southern Maryland Elec Coop Inc	OS	Note 1			
10	Southern Co Energy Marketing	OS	Note 1			
11	Southern Company	OS	Note 1			
12	Southern Electric Intl	OS	Note 1			
13	Southern Illinois Power Co-Op	OS	Note 1			
14	Southwest Power Pool	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447)

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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	Southwest Power Admin	OS	Note 1			
2	Southwestern Public Service Co	OS	Note 1			
3	Southwestn Elec Pwr Co	OS	Note 1,2			
4	Spark Energy, L.P.	OS	Note 1			
5	Split Rock Energy, LLC	OS	Note 1			
6	Strategic Energy Ltd.	OS	Note 1			
7	System Integration Agreement	OS	Note 1			
8	Teco Energy Source	OS	Note 1			
9	Tenaska Power Services Company	OS	Note 1			
10	Texas Genco, LP	OS	Note 1			
11	The Borough of Pitcairn, PA	OS	Note 1			
12	The Energy Authority	OS	Note 1			
13	Tractebel Energy Marketing	OS	Note 1			
14	TransAlta Energy Marketing US	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	TVA Bulk Power Trading	OS	Note 1			
2	TXU Energy Trading	OS	Note 1			
3	UBS AG, London Branch	OS	Note 1			
4	Union Power Partners	OS	Note 1			
5	Virginia Power Marketing	OS	Note 1			
6	Wabash Valley Power Assn Inc.	OS	Note 1			
7	Westar Energy Inc.	OS	Note 1			
8	Western Farmers Electric Coop	OS	Note 1			
9	Wisconsin Electric Power Co	OS	Note 1			
10	Wisconsin Public Service	OS	Note 1			
11	Wolverine Power Supply Coop	OS	Note 1			
12	WPS Energy Services Inc.	OS	Note 1			
13	Transmission Reclass	OS				
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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
		2,700		2,700	1
27,454		978,055		978,055	2
67,482		2,037,845		2,037,845	3
					4
6,805	67,265	147,841		215,106	5
32,287	471,074	902,965		1,374,039	6
	349,321			349,321	7
25,827	419,667	414,226		833,893	8
794	7,356	32,781		40,137	9
11,481	85,278	470,427		555,705	10
61,463	383,751	1,594,120		1,977,871	11
					12
45,426	1,215,916	769,542		1,985,458	13
21,868		656,297		656,297	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
12,257	253,607	211,715		465,322	1
213,436	1,660,789	5,015,330		6,676,119	2
60,107	652,205	1,026,714		1,678,919	3
288	538,648	21,563		560,211	4
					5
	501,008			501,008	6
					7
	25,445	22,944		48,389	8
					9
		-1,614		-1,614	10
5,408	11,622	104,002		115,624	11
2,316	4,841	76,004		80,845	12
		-246,784	246,784		13
18,819		537,761		537,761	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
-49		-4,126		-4,126	1
20		1,194		1,194	2
340		12,932		12,932	3
		-21,665		-21,665	4
-23,355		-1,008,467		-1,008,467	5
-4		-151		-151	6
		2,241		2,241	7
2,393,243		36,032,050		36,032,050	8
3,659		169,318		169,318	9
-8,107		-408		-408	10
		-1		-1	11
11,657		246,748		246,748	12
		-167		-167	13
90,797		3,602,119		3,602,119	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
15,744		786,995		786,995	1
		-2,590		-2,590	2
		-3,449		-3,449	3
		-116,715		-116,715	4
36,612		1,484,278		1,484,278	5
		-4,975		-4,975	6
		374,805		374,805	7
43,270		1,979,457		1,979,457	8
2		69		69	9
1,249		101,645		101,645	10
-5		-198		-198	11
		-15,037		-15,037	12
		4,442		4,442	13
292,182		9,355,364		9,355,364	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
		-50,501		-50,501	1
		2,761		2,761	2
5,017		65,336		65,336	3
		171,181		171,181	4
		-4		-4	5
		-1		-1	6
5,689		240,402		240,402	7
3,139		134,368		134,368	8
3,014		125,148		125,148	9
4,290		150,288		150,288	10
-14		889		889	11
		1,659		1,659	12
6,759		224,204		224,204	13
		-17,100		-17,100	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
2,926		-159,675		-159,675	1
83,932		2,986,958		2,986,958	2
-2,473		-261,537		-261,537	3
64,103		1,128,043		1,128,043	4
6,573		117,731		117,731	5
		4,454		4,454	6
		7,053		7,053	7
-30,893		-1,890,979		-1,890,979	8
		6,925		6,925	9
11,291		467,205		467,205	10
		-1,845		-1,845	11
119,422		5,567,076		5,567,076	12
4		63		63	13
		-879		-879	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
6,761		310,248		310,248	1
160,128		6,026,527		6,026,527	2
-91,190		-2,826,778		-2,826,778	3
-51,191		-2,469,451		-2,469,451	4
265		26,476		26,476	5
		-5		-5	6
		105,649		105,649	7
-265,810		-8,293,898		-8,293,898	8
13,009		556,649		556,649	9
239		340,960		340,960	10
384		10,643		10,643	11
61,031		2,273,149		2,273,149	12
-9,607		-424,889		-424,889	13
		29,956		29,956	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
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.
		-6,302		-6,302	1
		5		5	2
84,557		3,351,598		3,351,598	3
65,539		2,662,097		2,662,097	4
28		1,244		1,244	5
-326,998	15,408	-4,874,257		-4,858,849	6
149,399		6,240,875		6,240,875	7
29		775		775	8
-21		-1,791		-1,791	9
4,335		100,747		100,747	10
		-109		-109	11
		-6		-6	12
286		10,916		10,916	13
5,334		237,991		237,991	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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.
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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.
		62,341		62,341	1
		-18,914		-18,914	2
17,516		702,387		702,387	3
-4,698		-320,140		-320,140	4
42,107	362,197	1,135,840		1,498,037	5
953		126,949		126,949	6
		27,123		27,123	7
81,623		3,045,411		3,045,411	8
303		35,048		35,048	9
12,072		374,504		374,504	10
-15,807		-535,021		-535,021	11
		-26,261		-26,261	12
		3,944		3,944	13
-2,433		-90,066		-90,066	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

SALES FOR RESALE (Account 447) (Continued)

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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.
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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.
-3,879		-444,713		-444,713	1
2,335		120,209		120,209	2
1,656		86,349		86,349	3
265		13,145		13,145	4
21,760		798,418		798,418	5
		-185,473		-185,473	6
-21,930		-642,326		-642,326	7
84		67,872		67,872	8
9,226		307,861		307,861	9
38,949		1,136,659		1,136,659	10
1,989		67,544		67,544	11
		434		434	12
		-4,069		-4,069	13
27,269		1,046,927		1,046,927	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
-4,557		-150,033		-150,033	1
3,038		143,223		143,223	2
67		3,028		3,028	3
36,481		1,379,424		1,379,424	4
26,362		1,171,803		1,171,803	5
5,529		145,323		145,323	6
12,770		330,217		330,217	7
-147		-5,804		-5,804	8
		39,956		39,956	9
772		79,446		79,446	10
		-10		-10	11
		-2,140,514		-2,140,514	12
2,419		117,969		117,969	13
3,637		162,166		162,166	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
119,160		4,874,572		4,874,572	1
133,487		1,214,647		1,214,647	2
		-1		-1	3
1,376		54,709		54,709	4
-12,220		-386,301		-386,301	5
		1,910		1,910	6
2,617		-16,799		-16,799	7
-48,465		-3,636,394		-3,636,394	8
24,138		842,105		842,105	9
85,380	16,775	3,196,603		3,213,378	10
		-1		-1	11
10,629		394,528		394,528	12
		-71,578		-71,578	13
-123,549		-4,298,155		-4,298,155	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-266,021		-266,021	1
30,578		923,397		923,397	2
-2					3
6,556		244,058		244,058	4
		199		199	5
		-3		-3	6
52,394		1,492,063		1,492,063	7
		-7		-7	8
		-1		-1	9
		-3,129		-3,129	10
15,372		512,197		512,197	11
119,249		3,700,930		3,700,930	12
552		23,333		23,333	13
-1		5,789		5,789	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

SALES FOR RESALE (Account 447) (Continued)

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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.
-187					1
4		108		108	2
61,848	19,832	1,724,965		1,744,797	3
3		-4		-4	4
20,732		451,415		451,415	5
19,876		1,386,577		1,386,577	6
		-10,377,258		-10,377,258	7
560		63,811		63,811	8
17,717		489,583		489,583	9
		-412		-412	10
		5,046		5,046	11
-5,301		-243,940		-243,940	12
-29,301		-936,348		-936,348	13
20,977		718,226		718,226	14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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.
9,020		222,129		222,129	1
10,807		-34,179		-34,179	2
37,144		1,581,460		1,581,460	3
-454		-99,149		-99,149	4
156,461		4,718,416		4,718,416	5
81,768		2,282,448		2,282,448	6
6,469		68,912		68,912	7
156		5,638		5,638	8
3,171		151,201		151,201	9
-5,318		-237,109		-237,109	10
21,376		656,509		656,509	11
122,921		3,375,679		3,375,679	12
		-8,527,971	8,527,971		13
					14
94,936	0	3,018,600	0	3,018,600	
4,728,554	7,062,005	91,556,363	8,774,755	107,393,123	
4,823,490	**7,062,005**	**94,574,963**	**8,774,755**	**110,411,723**	

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

Note 1: AEP Power Sales Tariff, AEP Companies FERC Electric Tariff Original Volume 2.

Schedule Page: 310.1   Line No.: 11   Column: c

Note 2: Affiliate of Respondent

Schedule Page: 310.1   Line No.: 13   Column: j

Represents Transmission and Ancillary charges associated with account 447.

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	3,624,551	2,052,993
5	(501) Fuel	99,455,912	74,148,004
6	(502) Steam Expenses	1,927,389	3,430,575
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	92,324	208,747
10	(506) Miscellaneous Steam Power Expenses	2,554,749	2,178,427
11	(507) Rents		900
12	(509) Allowances	3,641,952	4,279,055
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	111,296,877	86,298,701
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,353,937	1,279,808
16	(511) Maintenance of Structures	210,819	417,625
17	(512) Maintenance of Boiler Plant	9,180,356	4,949,567
18	(513) Maintenance of Electric Plant	1,771,567	1,303,682
19	(514) Maintenance of Miscellaneous Steam Plant	379,127	477,504
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,895,806	8,428,186
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	124,192,683	94,726,887
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)		

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)
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)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	144,164,065	142,652,848
77	(556) System Control and Load Dispatching	1,039,844	112,314
78	(557) Other Expenses	3,577,433	3,021,047
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	148,781,342	145,786,209
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	272,974,025	240,513,096
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	356,557	360,761
84	(561) Load Dispatching	438,788	450,553
85	(562) Station Expenses	143,602	192,644
86	(563) Overhead Lines Expenses	500,076	302,265
87	(564) Underground Lines Expenses	531	40
88	(565) Transmission of Electricity by Others	-5,963,841	-5,538,749
89	(566) Miscellaneous Transmission Expenses	1,042,822	962,380
90	(567) Rents	3,159	1,734
91	TOTAL Operation (Enter Total of lines 83 thru 90)	-3,478,306	-3,268,372
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	123,713	115,234
94	(569) Maintenance of Structures	10,853	13,065
95	(570) Maintenance of Station Equipment	698,790	533,264
96	(571) Maintenance of Overhead Lines	1,300,271	1,660,872
97	(572) Maintenance of Underground Lines		615
98	(573) Maintenance of Miscellaneous Transmission Plant	1,984	1,288
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	2,135,611	2,324,338
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	-1,342,695	-944,034
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	861,900	941,673

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)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	332,738	253,963
106	(582) Station Expenses	236,891	182,781
107	(583) Overhead Line Expenses	172,972	290,311
108	(584) Underground Line Expenses	30,162	25,763
109	(585) Street Lighting and Signal System Expenses	14,091	82,708
110	(586) Meter Expenses	518,466	288,508
111	(587) Customer Installations Expenses	197,030	178,421
112	(588) Miscellaneous Expenses	2,699,274	2,688,932
113	(589) Rents	1,300,911	1,242,379
114	TOTAL Operation (Enter Total of lines 103 thru 113)	6,364,435	6,175,439
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	19,928	2,585
117	(591) Maintenance of Structures	10,277	34,686
118	(592) Maintenance of Station Equipment	743,177	345,922
119	(593) Maintenance of Overhead Lines	13,965,042	13,183,960
120	(594) Maintenance of Underground Lines	108,487	78,218
121	(595) Maintenance of Line Transformers	800,199	308,013
122	(596) Maintenance of Street Lighting and Signal Systems	71,655	5,432
123	(597) Maintenance of Meters	65,099	72,811
124	(598) Maintenance of Miscellaneous Distribution Plant	492,889	533,168
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	16,276,753	14,564,795
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	22,641,188	20,740,234
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	495,738	405,264
130	(902) Meter Reading Expenses	2,293,915	2,145,633
131	(903) Customer Records and Collection Expenses	6,111,240	5,194,576
132	(904) Uncollectible Accounts	18,470	-354,661
133	(905) Miscellaneous Customer Accounts Expenses	18,731	19,596
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	8,938,094	7,410,408
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	267,303	123,434
138	(908) Customer Assistance Expenses	954,082	796,786
139	(909) Informational and Instructional Expenses	95,141	775
140	(910) Miscellaneous Customer Service and Informational Expenses	1,819	332,391
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	1,318,345	1,253,386
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	25	24
145	(912) Demonstrating and Selling Expenses	11,145	6,808
146	(913) Advertising Expenses		26
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	11,170	6,858
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	6,446,547	7,479,705
152	(921) Office Supplies and Expenses	669,744	1,032,782
153	(Less) (922) Administrative Expenses Transferred-Credit	515,211	246,414

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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	7,241,789	2,501,624
156	(924) Property Insurance	315,460	388,920
157	(925) Injuries and Damages	962,365	1,015,491
158	(926) Employee Pensions and Benefits	3,849,173	4,397,549
159	(927) Franchise Requirements	151,836	172,146
160	(928) Regulatory Commission Expenses	154,951	275,988
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	115,401	193,159
163	(930.2) Miscellaneous General Expenses	2,185,785	1,512,443
164	(931) Rents	854,159	609,650
165	TOTAL Operation (Enter Total of lines 151 thru 164)	22,431,999	19,333,043
166	Maintenance		
167	(935) Maintenance of General Plant	1,493,702	2,010,572
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	23,925,701	21,343,615
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	328,465,828	290,323,563

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	AEG Generating Co. (AEP affiliate)	RQ	AEG 1			
2	AEP Texas Central Co. (AEP affiliate)	OS	Note 1			
3	AEP Texas North Co. (AEP affiliate)	OS	Note 1			
4	Allegheny Power GM	OS	Note 1			
5	AEP Service Corp. (AEP affiliate)	OS	APCO 20			
6	Buckeye Rural Electric Admin.	OS	Note 1			
7	Cincinnati Gas & Electric Co.	OS	Note 1			
8	Consumers Energy Traders	OS	Note 1			
9	Detroit Edison Merch	OS	Note 1			
10	DP&L Power Services	OS	Note 1			
11	Duquesne Light Company	OS	Note 1			
12	East KY Power Co-Op Power Mkt	OS	KYPCO 14			
13	FirstEnergy Trading Services	OS	Note 1			
14	Indianapolis Power & Light Co.	OS	Note 1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	LG&E Utilities Power Sales	OS	Note 1			
2	Loop Interchange	OS	Note 1			
3	National Power Cooperative Inc	OS	Note 1			
4	NIPSCO Energy Management	OS	Note 1			
5	OVEC Power Scheduling	OS	Note 1			
6	PJM Interconnection	OS	Note 1			
7	Public Service Co of OK (AEP affil)	OS	Note 1			
8	Southwestern Elec Pwr Co (AEP affil)	OS	Note 1			
9	System Integration Agreement	OS	Note 1			
10	Misc. MWH Adjustments					
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,555,156			38,733,751	33,740,956		72,474,707	1
57				-15,461		-15,461	2
				-6,331		-6,331	3
16				1,543		1,543	4
3,057,230				68,072,064		68,072,064	5
				619,512		619,512	6
31				3,330		3,330	7
65				6,684		6,684	8
3				365		365	9
2				331		331	10
4				737		737	11
1				435		435	12
37				3,911		3,911	13
6				478		478	14
5,943,392	1,860	2,464	39,808,230	104,355,835		144,164,065	

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)	
11				1,217		1,217	1
	1,860	2,464		-10,570		-10,570	2
4,425			1,074,479	348,353		1,422,832	3
10				985		985	4
				17		17	5
24,466				1,428,150		1,428,150	6
3,044				147,609		147,609	7
1,914				84,967		84,967	8
				-73,447		-73,447	9
296,914							10
							11
							12
							13
							14
5,943,392	1,860	2,464	39,808,230	104,355,835		144,164,065	

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

Statistical classification "OS" includes non - firm hourly, daily, and weekly purchases that the supplier may cancel, if necessary, with little notice.

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

Note 1: AEP Sales Tafiff - AEP Companies FERC Electric Tariff original Volume 2.

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

The Respondent, Indiana Michigan Power Company, Ohio Power Company, Columbus Southern Power Company and Appalachian Power Company are associated companies and members of the American Electric Power System Power Pool, whose electric facilities are inter-connected at a number of points and are operated in a fully coordinated manner on a system pool basis.

APCO - Appalachian Power Company
OPCO - Ohio Power Company
IMPCO - Indiana Michigan Power Company
KPCO - Kentucky Power Company
CSPCO - Columbus Southern Power Company

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

Receipts of power from the members of the AEP System Power Pool, governed by the terms of the interconnection agreement dated July 6, 1951, as amended.

Schedule Page: 326.1 Line No.: 10 Column: g

Detail of Misc MWH Adjustments	MWH
Power Transfer	(94)
Bookouts/Options	90,298
East/West Transfer	268
Spot Energy (PJM)	(35,708)
Inadvertant	95,688
Pool Adjustment	159,983
By-Thru	(425)
DOW Plaquemine	(13,096)
Total Misc MWH Adjustments	**296,914**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Allegheny Energy Supply Co LLC	Various	Various	LFP
2	Ameren Energy Inc	Various	Various	OS
3	American Municipal Power - Ohio	Various	Various	FNO
4	Aquila Merchant Services Inc	Various	Various	OS
5	J. Aron & Company	Various	Various	OS
6	Blue Ridge Power Agency	Cinergy	Blue Ridge Agency	LFP
7	Black Oak Capital LLC	Various	Various	OS
8	B.P. Energy Company	Various	Various	OS
9	Buckeye Rural Electric Admin	Cardinal Operating Co	Various	FNO
10	Calpine Power Service Company	Various	Various	OS
11	CAM Energy Products	Various	Various	OS
12	City of Dowagiac, MI	Various	Various	LFP
13	Consumers Energy Traders	Various	Various	LFP
14	CMS Marketing Services & Trading	Various	Various	OS
15	Connective Energy Supply Inc	Various	Various	OS
16	Conoco Inc	Various	Various	OS
17	Carolina Power & Light	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Cinergy Power Marketing & Trading	Various	Various	OS
2	Cleveland Public Power	Various	Various	LFP
3	Constellation Power Source	Various	Various	LFP
4	Cargill - Alliant	Various	Various	OS
5	Central Virginia Electric Coop	Various	Various	LFP
6	Dominion Energy Marketing	Various	Various	OS
7	Detroit Edison Merchants	Various	Various	OS
8	Duke Energy Trading	Various	Various	LFP
9	DP&L Power Services	Various	Various	OS
10	DTE Energy Trading Inc	Various	Various	OS
11	Duke Power Co	Various	Various	OS
12	Dynergy Power Marketing Inc	Various	Various	LFP
13	East KY Power Coop Power Marketing	Various	Various	OS
14	Edison Mission Mktg & Trading	Various	Various	OS
15	Entergy-Koch Trading LP	Various	Various	OS
16	PP&L Energy Plus Co.	Various	Various	OS
17	Exelon Generation - Power Team	Various	Various	LFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	FirstEnergy Trading Services	Various	Various	OS
2	Florida Power Corporation	Various	Various	OS
3	Hoosier Power Market	Various	Various	LFP
4	HQ Energy Services US Inc	Various	Various	OS
5	Indiana Municipal Power Agency	Various	Various	OS
6	Joint Operating Group	Various	Various	LFP
7	LG&E Utilities Power Sales	Various	Various	OS
8	Mirant Americas Energy Mrktg LP	Various	Various	OS
9	Minnesota Power	Various	Various	OS
10	Morgan Stanley Capt.	Various	Various	OS
11	NC Electric Membership Corp.	Various	Various	LFP
12	NIPSCO Energy Management	Various	Various	OS
13	NRG Power Marketing Inc	Various	Various	OS
14	Old Dominion Elec.	Various	Various	OS
15	Orion Power Midwest	Various	Various	OS
16	Occidental Power Services	Various	Various	OS
17	PSEG Energy Resources & Trade	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Progress Ventures	Various	Various	OS
2	Powerex	Various	Various	OS
3	Rainbow Energy Marketing	Various	Various	OS
4	Reliant Energy Services	Various	Various	OS
5	Scana Energy Marketing	Various	Various	OS
6	Stryka Energy Fund	Various	Various	OS
7	Southern Electric International	Various	Various	OS
8	Strategic Energy LTD	Various	Various	LFP
9	Southeast Power Administration	Various	Various	LFP
10	SESCO Enterprises LLC	Various	Various	OS
11	Sempra Energy Trading	Various	Various	OS
12	Split Rock Energy LLC	Various	Various	OS
13	Sturgis, City of	Various	Various	LFP
14	The Energy Authority	Various	Various	OS
15	TransAlta Energy Marketing US	Various	Various	OS
16	Tenaska Power Services Company	Various	Various	OS
17	TVA Bulk Power Trading	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Virginia Power Marketing	Various	Various	OS
2	Williams Energy Services Co	Various	Various	OS
3	Wolverine Power Supply Coop	Various	Various	OS
4	WPS Energy Services	Various	Various	OS
5	Wisconsin Public Service	Various	Various	OS
6	Western Resources Gen. Svcs.	Various	Various	OS
7	Wabash Valley Power Assn Inc	Various	Wabash Vall	LFP
8	West Virginia Power	Various	Various	LFP
9	PJM Network Integration Transmission	Various	Various	FNO
10	PJM Point to Point Transmission Service	Various	Various	OLF
11	PJM Transmission Owner Administration	Various	Various	OS
12	SECA Transmission Revenue	Various	Various	OS
13				
14				
15				
16				
17				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Note 1	Various	Various	34	100,421	100,421	1
Note 1	Various	Various	22	5,010	5,010	2
Note 1	Various	Various	23	124,701	124,701	3
Note 1	Various	Various		68	68	4
Note 1	Various	Various		3,162	3,162	5
Note 1	Various	Various		140,038	140,038	6
Note 1	Various	Various		185	185	7
Note 1	Various	Various		4,181	4,181	8
OPCO 69	Various	Various	60	410,094	410,094	9
Note 1	Various	Various		2,380	2,380	10
Note 1	Various	Various		7,507	7,507	11
Note 1	Various	Various		4,488	4,488	12
Note 1	Various	Various	14	30,157	30,157	13
Note 1	Various	Various	7	31,695	31,695	14
Note 1	Various	Various		22,324	22,324	15
Note 1	Various	Various		282	282	16
Note 1	Various	Various		5,359	5,359	17
			371	**2,257,671**	**2,257,671**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Note 1	Various	Various		77,198	77,198	1
Note 1	Various	Various	4	9,414	9,414	2
Note 1	Various	Various	7	27,695	27,695	3
Note 1	Various	Various		73,126	73,126	4
Note 1	Various	Various	2	12,706	12,706	5
Note 1	Various	Various		7,296	7,296	6
Note 1	Various	Various		14,952	14,952	7
Note 1	Various	Various	50	120,582	120,582	8
Note 1	Various	Various		1,566	1,566	9
Note 1	Various	Various	14	69,246	69,246	10
Note 1	Various	Various				11
Note 1	Various	Various	15	86,123	86,123	12
Note 1	Various	Various		2,800	2,800	13
Note 1	Various	Various		14,381	14,381	14
Note 1	Various	Various		40,169	40,169	15
Note 1	Various	Various		12,904	12,904	16
Note 1	Various	Various	71	223,345	223,345	17
			371	**2,257,671**	**2,257,671**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
Note 1	Various	Various		3,686	3,686	1
Note 1	Various	Various		466	466	2
Note 1	Various	Various		522	522	3
Note 1	Various	Various				4
Note 1	Various	Various		36,101	36,101	5
Note 1	Various	Various	3	19,890	19,890	6
Note 1	Various	Various		858	858	7
Note 1	Various	Various		12,710	12,710	8
Note 1	Various	Various		1,295	1,295	9
Note 1	Various	Various	8	56,748	56,748	10
Note 1	Various	Various	7	50,356	50,356	11
Note 1	Various	Various		7	7	12
Note 1	Various	Various		7	7	13
Note 1	Various	Various	2	20,920	20,920	14
Note 1	Various	Various		333	333	15
Note 1	Various	Various		5,244	5,244	16
Note 1	Various	Various		5,614	5,614	17
			371	**2,257,671**	**2,257,671**	

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.
Note 1	Various	Various		1,005	1,005	1
Note 1	Various	Various		9,847	9,847	2
Note 1	Various	Various		1,995	1,995	3
Note 1	Various	Various		230	230	4
Note 1	Various	Various		216	216	5
Note 1	Various	Various		965	965	6
Note 1	Various	Various		1,117	1,117	7
Note 1	Various	Various		37,834	37,834	8
Note 1	Various	Various		1,273	1,273	9
Note 1	Various	Various		251	251	10
Note 1	Various	Various		1,758	1,758	11
Note 1	Various	Various		22,977	22,977	12
Note 1	Various	Various	2	12,816	12,816	13
Note 1	Various	Various		99	99	14
Note 1	Various	Various		5,069	5,069	15
Note 1	Various	Various		3,943	3,943	16
Note 1	Various	Various		558	558	17
			371	**2,257,671**	**2,257,671**	

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.
Note 1	Various	Various		703	703	1
Note 1	Various	Various		2,755	2,755	2
Note 1	Various	Various		46	46	3
Note 1	Various	Various		285	285	4
Note 1	Various	Various		10,678	10,678	5
Note 1	Various	Various		4,833	4,833	6
Note 1	Various	Various	19	210,127	210,127	7
Note 1	Various	Various	7	25,979	25,979	8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
						13
						14
						15
						16
						17
			371	**2,257,671**	**2,257,671**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
	515,016	36,398	551,414	1
	18,217	1,323	19,540	2
	351,575	61,246	412,821	3
	803	49	852	4
	23,930	1,797	25,727	5
	240,117	28,385	268,502	6
	1,328	78	1,406	7
	26,271	1,789	28,060	8
	1,221,897	88,402	1,310,299	9
	2,366	141	2,507	10
	27,415	2,214	29,629	11
	6,407	2,551	8,958	12
	293,376	23,990	317,366	13
	103,031	8,530	111,561	14
	131,137	8,446	139,583	15
	1,872	133	2,005	16
	24,960	1,671	26,631	17
1,716,710	**7,828,874**	**1,583,356**	**11,128,940**	

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.
	103,236	7,892	111,128	1
	70,501	11,573	82,074	2
	138,392	8,917	147,309	3
	224,052	14,593	238,645	4
	14,888	-5,978	8,910	5
	24,485	1,544	26,029	6
	73,448	4,798	78,246	7
	513,184	37,582	550,766	8
	6,881	455	7,336	9
	302,447	18,110	320,557	10
	1		1	11
	292,653	26,143	318,796	12
	66,004	64	66,068	13
	66,623	4,308	70,931	14
	14,868	1,012	15,880	15
	58,348	3,861	62,209	16
	1,134,382	112,851	1,247,233	17
1,716,710	**7,828,874**	**1,583,356**	**11,128,940**	

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.
	5,926	7,078	13,004	1
	2,198	127	2,325	2
	7,424	1,528	8,952	3
	1		1	4
	129,499	18,109	147,608	5
	32,395	3,548	35,943	6
	3,123	184	3,307	7
	71,331	4,211	75,542	8
	4,301	284	4,585	9
	274,405	22,718	297,123	10
	225,968	13,294	239,262	11
	37	2	39	12
	90	8	98	13
	116,538	11,911	128,449	14
	68,776	6,181	74,957	15
	21,397	1,518	22,915	16
	137,375	16,351	153,726	17
1,716,710	**7,828,874**	**1,583,356**	**11,128,940**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.
	12,841	856	13,697	1
	39,678	2,597	42,275	2
	1,590	104	1,694	3
	3,534	221	3,755	4
	10,200	839	11,039	5
	5,003	410	5,413	6
	10,192	639	10,831	7
	67,824	37,621	105,445	8
	15,319	1,248	16,567	9
	1,268	101	1,369	10
	7,488	487	7,975	11
	86,137	5,568	91,705	12
	25,847	4,910	30,757	13
	383	23	406	14
	22,275	1,363	23,638	15
	2,731	182	2,913	16
	2,249	134	2,383	17
1,716,710	**7,828,874**	**1,583,356**	**11,128,940**	

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.
	5,819	382	6,201	1
	10,257	628	10,885	2
	157	9	166	3
	1,338	79	1,417	4
	60,328	4,160	64,488	5
	2,131	134	2,265	6
	182,190	2,325	184,515	7
	57,200	13,605	70,805	8
1,005,643			1,005,643	9
711,067			711,067	10
		58,907	58,907	11
		823,904	823,904	12
				13
				14
				15
				16
				17
1,716,710	**7,828,874**	**1,583,356**	**11,128,940**	

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

Note 1
AEP Point - to -Point Tariff and 2nd Revised Tariff - AEP Companies FERC Electric Tariff Original Volume 1. Under the tariff, the transaction varies by megawatts and duration.

Schedule Page: 328.4 Line No.: 9 Column: e

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)	TRANSFER OF ENERGY: 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	Concurrent Energy							
2	East KY Power Coop	LFP	54,131	54,131			109,455	109,455
3								
4	AEP Trans Equil Agrmt	FNS					-6,075,045	-6,075,045
5								
6	AEP Service Corporation	OS					1,749	1,749
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		54,131	54,131			-5,963,841	-5,963,841

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

The Respondent, Appalachian Power Company, Columbus Southern Power Company, Indiana & Michigan Power Company and Ohio 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 investments 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 designated by brackets "()" which are recorded in account 565.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	123,856
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	22,500
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	1,886,526
7	AEP Service Corporation Billings	113,532
8	Intercompany Billings	-9,149
9	AEP Utility Funding LLC (Money Pool)	26,616
10	Adjustments to balance bank accts to general ledger	20,613
11	Miscellaneous Items	1,291
12		
13		
14		
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16		
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46	TOTAL	2,185,785

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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			3,447,648		3,447,648
2	Steam Production Plant	12,885,962	3,858,878	552,360		17,297,200
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	6,510,774				6,510,774
8	Distribution Plant	15,190,439				15,190,439
9	General Plant	752,083		3,408		755,491
10	Common Plant-Electric					
11	TOTAL	35,339,258	3,858,878	4,003,416		43,201,552

B. Basis for Amortization Charges

Section A, Line 1, Column (d) represents amortization of franchises over the life of the franchise ($380) and amortization of capitalized software development costs over a 5 year life for minor projects and up to a 10 year life for major projects ($3,447,268).

Section A, Line 2, Column (d) represents amortization of Selective Catalytic Reduction Catalyst equipment over a useful life range defined as:

SCR Catalyst Layer 1	15years	($217,404)
SCR Catalyst Layer 2	19 yaers	(171,697)
SCR Catalyst Layer 3	10 years	(163,259)
Total		($552,360)

Section A, Line 9, Column (d) represents amortization of Hazard Building lease over the estimated useful life of the lease ($3,408).

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	445,847			2.62		
13	Transmission	383,197			1.71		
14	Disrtibution	437,319			3.52		
15	General	28,359			2.54		
16							
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Schedule Page: 336 Line No.: 12 Column: b

NOTE (A)

Depreciation was accrued monthly on functional composite bases at the above rates per annum on electric Plant In Service Less La

1. Steam Production Plant
2. Transmission Plant
3. Distribution Plant
4. General Plant

NOTE (B)

Depreciable Plant Base at year end. Also see Note (A).

NOTE (C)

Estimated Average Service Lives and, to some extent, Net Salvage Values are determined by a number of factors, including not only the physical characteristics of the property (which themselves vary from time to time), but also management's judgement as reflected in the choice of equipment (as between alternatives) and the establishment and implementation of maintenance policy and operation practice.

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	Federal Energy Regulatory Commission				
2	-Annual Assessment	153,201		153,201	
3					
4	Commonwealth of Kentucky				
5	-Settlement	1,750		1,750	
6					
7					
8					
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45					
46	TOTAL	154,951		154,951	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
	928	153,201					2
							3
							4
	928	1,750					5
							6
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							43
							44
							45
		154,951					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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
  (3) Transmission
    a. Overhead
    b. Underground
  (4) Distribution
  (5) Environment (other than equipment)
  (6) Other (Classify and include items in excess of $5,000.)
  (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	DEMONSTRATIONS PERFORMED INTERNALLY	
3	A(1)b: Generation: Fossil-fuel steam	Advanced Generation Program Mgt
4		9 Items < $5,000
5		
6	A(1)e: Generation: Unconventional generation	2 Items < $5,000
7		
8	A(3): Transmission	Transmission Program Management
9		
10	A(3)a: Transmission: Overhead	9 Items < $5,000
11		
12	A(3)b: Transmission: Underground	1 Item < $5,000
13		
14	A(4): Distribution	Advanced Distr. Program Mgt.
15		CEA Distribution Projects
16		System Disturbance Monitoring
17		9 Items < $5,000
18		
19	A(5): Environment (other than equipment)	Ash Pond SCR Ammonia Mitigation
20		Environmental Controls Program
21		EPRI Environmental Control Pro
22		General Mercury Science & Tech
23		3 Items < $5,000
24		
25	A(6)a: Other	1 Item < $5,000
26		
27	A(6)g: Other	R&D Program Development
28		DTC Development and Demonstrat
29		GSU Acoustic Emission Monitors
30		4 Items < $5,000
31	A(7) TOTAL COST INCURRED INTERNALLY	
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (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 EXTERNALLY	
3	B(1): Research Support to the Elec. Research	
4	Council or the Elec. Power Research Inst.	Advanced Dist EPRI Base Prog
5		Corporate Issues EPRI Base Pla
6		EPRI Climate Contingency Ph II
7		EPRI Environmental Science Pro
8		Generation EPRI Base Program
9		Transmission EPRI Base Program
10		27 Items < $5,000
11		
12	B(4): Research Support to Others	NEETRAC Membership
13		NEETRAC Project Purchases
14		10 Items < $5,000
15	B(5) TOTAL COSTS INCURRED EXTERNALLY	
16		
17		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 $5,000 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 $5,000 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
5,494		506	5,494		3
7,326		506	7,326		4
					5
4,457		506	4,457		6
					7
9,949		566	9,949		8
					9
16,846		566	16,846		10
					11
950		566	950		12
					13
6,838		588	6,838		14
5,391		588	5,391		15
5,363		588	5,363		16
11,015		588	11,015		17
					18
8,484		506	8,484		19
16,026		506	16,026		20
37,853		506	37,853		21
48,284		506	48,284		22
4,303		506	4,303		23
					24
3,274		506	3,274		25
					26
104,165		Various	104,165		27
5,258		Various	5,258		28
13,032		Various	13,032		29
3,085		Various	3,085		30
317,393			317,393		31
					32
					33
					34
					35
					36
					37
					38 1
					2

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 $5,000 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 $5,000 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.
					3
	18,615	588	18,615		4
	18,102	Various	18,102		5
	5,877	506	5,877		6
	154,931	506	154,931		7
	18,029	506	18,029		8
	15,544	566	15,544		9
	24,958	Various	24,958		10
					11
	8,821	588	8,821		12
	11,654	588	11,654		13
	20,173	Various	20,173		14
	296,704		296,704		15
					16
					17
					18
					19
					20
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	4,006,843		
4	Transmission	489,223		
5	Distribution	791,941		
6	Customer Accounts	1,517,726		
7	Customer Service and Informational	319,568		
8	Sales			
9	Administrative and General	924,889		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	8,050,190		
11	Maintenance			
12	Production	3,378,662		
13	Transmission	818,184		
14	Distribution	4,442,994		
15	Administrative and General	634,435		
16	TOTAL Maint. (Total of lines 12 thru 15)	9,274,275		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	7,385,505		
19	Transmission (Enter Total of lines 4 and 13)	1,307,407		
20	Distribution (Enter Total of lines 5 and 14)	5,234,935		
21	Customer Accounts (Transcribe from line 6)	1,517,726		
22	Customer Service and Informational (Transcribe from line 7)	319,568		
23	Sales (Transcribe from line 8)			
24	Administrative and General (Enter Total of lines 9 and 15)	1,559,324		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	17,324,465	1,232,373	18,556,838
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Enter Total of lines 28 thru 37)			
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)			

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	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	17,324,465	1,232,373	18,556,838
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	6,709,186	477,257	7,186,443
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	6,709,186	477,257	7,186,443
69	Plant Removal (By Utility Departments)			
70	Electric Plant	1,189,154	84,590	1,273,744
71	Gas Plant			
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	1,189,154	84,590	1,273,744
74	Other Accounts (Specify, provide details in footnote):			
75	152 - Fuel Stock Expense Undistributed	879,139		879,139
76	163 - Stores Expense Undistributed	1,067,052	-1,067,052	
77	184 - Clearing Accounts	727,168	-727,168	
78	185 - ODD Temporary Facilities	23,208		23,208
79	186 - Misc Deferred Debits	518,143		518,143
80	188 - Research & Development	1,073		1,073
81	242 - Misc Current & Accrued Liabilities	-22,000		-22,000
82	426 - Donations	52,585		52,585
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,246,368	-1,794,220	1,452,148
96	TOTAL SALARIES AND WAGES	28,469,173		28,469,173

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			678,284		$57.71MWMo	555,156
2	Reactive Supply and Voltage			865,426		$73.00MWMo	806,463
3	Regulation and Frequency Response				455	$53.00MWMo	24,126
4	Energy Imbalance						-62,224
5	Operating Reserve - Spinning				455	$79.50MWMo	36,189
6	Operating Reserve - Supplement				225	$79.50MWMo	17,906
7	Other						
8	Total (Lines 1 thru 7)			1,543,710	1,135		1,377,616

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

Includes the Company’s member-load-ratio share of "Scheduling, System Control and Dispatch" purchased from non-affiliated parties, as well as the company’s member-load-ratio share of the non-billed charges corresponding to its internal load. The Unit of Measure employed for the internal load calculation corresponds to that of the AEP System’s OATT, namely $57.71/MW-Mo, and only covers the January-September 2004 time period, i.e., prior to AEP’s joining the PJM RTO. Of the total $'s shown, $643,979 corresponds to the internal load’s charges. The difference pertains to purchases from non-affiliated parties for the calendar year 2004, for which a Unit of Measure can not be derived, inasmuch as it varies based on each party’s OATT.

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

See note for line 1 column b.

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

A derivation of "number of units" for this ancillary service is not feasible, inasmuch as: the point-to-point transmission customer is charged the unit of measure for its reservation (or prorated accordingly for reservations of less than a month's duration) while the Network Transmission Service (NTS) customer is charged the unit of measure times its demand at the time of the AEP System's monthly transmission peak demand.

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

All amounts in column g represent the Company's member-load-ratio (MLR) share of AEP System's ancillary services revenues

Schedule Page: 398 Line No.: 2 Column: b

Includes the Company’s member-load-ratio share of "Reactive Supply and Voltage" purchased from non-affiliated parties, as well as the company’s member-load-ratio share of the non-billed charges corresponding to its internal load. The Unit of Measure employed for the internal load calculation corresponds to that of the AEP System’s OATT, namely $73.00/MW-Mo, and only covers the January-September 2004 time period, i.e., prior to AEP’s joining the PJM RTO. Of the total $'s shown, $814,599 corresponds to the internal load’s charges. The difference pertains to purchases from non-affiliated parties for the calendar year 2004, for which a Unit of Measure can not be derived, inasmuch as it varies based on each party’s OATT.

Schedule Page: 398 Line No.: 2 Column: c

See note for line 2 column b.

Schedule Page: 398 Line No.: 2 Column: e

A derivation of "number of units" for this ancillary service is not feasible, inasmuch as: the point-to-point transmission customer is charged the unit of measure for its reservation (or prorated accordingly for reservations of less than a month's duration) while the Network Transmission Service (NTS) customer is charged the unit of measure times its demand at the time of the AEP System's monthly transmission peak demand.

Schedule Page: 398 Line No.: 4 Column: e

Applicable to certain NTS customers only, as needed. The net revenues/(charges) to the Company are shown, representing the Company's MLR share of the AEP System's total net. A derivation of "number of units" or "unit of measure" is not feasible, inasmuch as: on an hourly basis, the customer's transmission schedule is compared versus its actual load demand: if its schedule is higher (dump energy into AEP), it receives a firm load lambda per MW payment; if the schedule is lower (excess energy provided by AEP), it pays $100/MW.

Schedule Page: 398 Line No.: 4 Column: f

See note for line 4 column e.

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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 (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January									
2	February									
3	March									
4	Total for Quarter									
5	April									
6	May									
7	June									
8	Total for Quarter									
9	July									
10	August									
11	September									
12	Total for Quarter									
13	October									
14	November									
15	December									
16	Total for Quarter									
17	Total for Year to									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	6,550,509
4	Nuclear	
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	6,550,509
10	Purchases	5,943,392
11	Power Exchanges:	
12	Received	1,860
13	Delivered	2,464
14	Net Exchanges (Line 12 minus line 13)	-604
15	Transmission For Other (Wheeling)	
16	Received	2,257,671
17	Delivered	2,257,671
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)	12,493,297

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,976,594
23	Requirements Sales for Resale (See instruction 4, page 311.)	94,936
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,728,554
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	693,213
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,493,297

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	1,194,237	393,430	1,478	31	900
30	February	1,047,392	310,713	1,391	16	900
31	March	901,856	222,580	1,351	23	800
32	April	982,411	407,651	1,167	5	800
33	May	957,825	360,298	1,132	25	1300
34	June	1,127,724	526,785	1,174	17	1400
35	July	1,209,142	559,155	1,209	13	1500
36	August	1,070,387	434,111	1,228	3	1600
37	September	1,038,565	477,930	1,060	1	1700
38	October	941,955	382,657	950	18	800
39	November	873,409	275,402	1,220	15	900
40	December	1,148,394	377,842	1,615	20	900
41	TOTAL	12,493,297	4,728,554			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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: *BIG SANDY* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL	
3	Year Originally Constructed	1963	
4	Year Last Unit was Installed	1969	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1096.80	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	1088	0
7	Plant Hours Connected to Load	7721	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1060	0
10	When Limited by Condenser Water	1060	0
11	Average Number of Employees	131	0
12	Net Generation, Exclusive of Plant Use - KWh	6550509000	0
13	Cost of Plant: Land and Land Rights	1076546	0
14	Structures and Improvements	36149758	0
15	Equipment Costs	417839232	0
16	Asset Retirement Costs	0	0
17	Total Cost	455065536	0
18	Cost per KW of Installed Capacity (line 17/5) Including	414.9029	0.0000
19	Production Expenses: Oper, Supv, & Engr	3624551	0
20	Fuel	98292159	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1927389	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	92324	0
26	Misc Steam (or Nuclear) Power Expenses	2554749	0
27	Rents	0	0
28	Allowances	3641952	0
29	Maintenance Supervision and Engineering	1353937	0
30	Maintenance of Structures	210819	0
31	Maintenance of Boiler (or reactor) Plant	9180356	0
32	Maintenance of Electric Plant	1771567	0
33	Maintenance of Misc Steam (or Nuclear) Plant	379127	0
34	Total Production Expenses	123028930	0
35	Expenses per Net KWh	0.0188	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	2607559	24050	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11992	138842	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.737	56.648	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	36.220	50.526	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.510	8.665	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	14.820	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9568.000	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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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

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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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. 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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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)
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46						

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/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
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	ST	0.13		1
2	0700 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ALUM	24.20		1
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ST	4.79		1
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUM	12.65		1
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ST	3.04		1
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUMT	58.26		1
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	ST	154.74		1
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	ST	8.36		1
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	WP	45.62		1
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	ST	0.72		1
11	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ALUM	12.08		1
12	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ST	14.77		1
13	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	ST	0.33		1
14	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	ST	1.10	1.10	1
15	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	6.17		1
16	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	22.35		1
17	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	1.47		1
18	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	WP	16.92	16.92	1
19	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	ST	0.64		2
20	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	ALUMT	32.43		1
21	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	10.05		1
22	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	16.41	0.33	1
23	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	ST	0.71	14.41	1
24	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	WP	0.38		1
25	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	WP	7.90		1
26	0115 CHADWICK	COALTON	138.00	138.00	WP	0.98		1
27	0133 CHADWICK		138.00	138.00				
28	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	WP	5.08	1.58	1
29	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	WP	26.40		1
30	0120 HATFIELD	SPRIGG	138.00	138.00	WP	5.88		1
31	0121 HATFIELD	INEZ	138.00	138.00	WP	14.67		1
32	0122 INEZ	LOVELY	138.00	138.00	WP	6.86		1
33	0126 INEZ	MARTIKI	138.00	138.00	WP	0.33		1
34	0127 BIG SANDY	INEZ	138.00	138.00	ST	23.00		1
35	0106 DORTON	FLEMING	138.00	138.00	WP	7.64		1
36					TOTAL	1,225.65	40.26	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60		1
2	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01		1
3	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
4	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22		2
5	0130 JOHNS CREEK	SPRIGG	138.00	138.00	ST	13.00		
6	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00		1
7	0128 INEZ	JOHNS CREEK	138.00	138.00	ST	17.00		
8	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	ST	22.00		
9	0132 GRANGSTON LOOP		138.00	138.00				
10								
11	LINES < 132KV		69.00	69.00		592.76	5.92	
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					TOTAL	1,225.65	40.26	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 MCMA	258	10,045	10,303					1
954 MCMA	554,508	5,276,357	5,830,865					2
								3
954 MCMA	3,159,675	15,941,538	19,101,213					4
								5
								6
351.5 VAR	17,020,130	102,854,624	119,874,754	105,300	273,506		378,806	7
954 MCMA	177,562	1,019,199	1,196,761	3,415	8,869		12,284	8
500 MCMCU	197,622	2,230,733	2,428,355					9
				18,927	49,161		68,088	10
556.5 VAR	492,653	1,753,440	2,246,093					11
								12
1033.5 VAR	8,672	63,923	72,595					13
397.5 MA	4,478	121,821	126,299					14
397.5 MCMCU	59,507	477,449	536,956					15
								16
636 MCMA	84,068	1,288,061	1,372,129					17
								18
397 MCMA	2,128	444,269	446,397					19
397.5 MCMA	519,478	2,505,383	3,024,861					20
								21
								22
795 MCMA	16,110	609,142	625,252					23
								24
795 MCMA	52,422	258,407	310,829					25
795 MCMA	291,969	422,415	714,384					26
	67,982	914,472	982,454					27
556.5 MCM	408,799	65,178	473,977					28
795 MCMA	555,042	944,527	1,499,569					29
1033 MCM		1,506,763	1,506,763					30
10335 VAR	633,040	4,452,788	5,085,828					31
10335 VAR	2,783	571,688	574,471					32
10335 VAR	2,269	56,174	58,443					33
795 MCMA	1,356,990	12,407,718	13,764,708					34
795 MCMA	217,206	1,174,257	1,391,463					35
	30,285,296	224,660,281	254,945,577	500,607	1,300,270		1,800,877	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397 MCMA	125,056	918,630	1,043,686					1
10335 VAR		97,436	97,436					2
	51,485		51,485					3
795 ACSR	1,393	225,286	226,679					4
1033 MCM		3,833,913	3,833,913					5
1351 KCM	650	1,179,194	1,179,844					6
2-556.5 MCM	989,470	9,907,226	10,896,696					7
1033 MCM	137,556	7,498,274	7,635,830					8
	4,103	1	4,104	130,857	339,886		470,743	9
								10
	3,090,232	43,629,950	46,720,182	242,108	628,848		870,956	11
								12
								13
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								17
								18
								19
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								29
								30
								31
								32
								33
								34
								35
	30,285,296	224,660,281	254,945,577	500,607	1,300,270		1,800,877	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	None Added in 2004						
2							
3							
4							
5							
6							
7							
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41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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
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									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	COLEMAN-COLEMAN	T-U	69.00	12.00	
2		T-U	69.00	34.00	
3	COLLIER-TILLIE	D-U	69.00	34.00	
4	DEWEY-ODDS	T-U	138.00	69.00	12.00
5		D-U	138.00	34.00	
6	DORTON-DORTON	T-U	138.00	46.00	
7		T-U	34.50	2.50	
8	DRAFFIN	D-U	46.00	12.00	
9	EAST PRESTONBURG	D-U	46.00	12.00	
10	EAST PRESTONSBURG - FUTURE	D-U	46.00	12.00	
11	ELKHORN CITY-ELKHORN CITY	T-U	69.00	46.00	
12		T-U	69.00	12.00	
13	ELKWOOD-VIRGIE	T-U	46.00	34.50	6.50
14	ENGLE-ENGLE	D-U	69.00	34.50	
15	FALCON	D-U	69.00	46.00	
16		D-U	69.00	12.00	
17	FEDS CREEK-NIGH	D-U	69.00	12.00	
18	FLEMING-FLEMING	T-U	138.00	69.00	46.00
19		T-U	69.00	12.00	
20	FORDS BRANCH-SHELBIANA	D-U	46.00	34.50	12.00
21	FORTY-SEVENTH ST.-ASHLAND	D-U	69.00	13.09	
22	GARRETT	D-U	46.00	12.00	
23	GRAYSON	D-U	69.00	12.00	
24	HADDIX-HADDIX	D-U	69.00	34.50	
25	HATFIELD-SO. WILLIAMSON	T-U	138.00	69.00	46.00
26		T-U	46.00	7.20	
27	HAZARD-LOTHAIR	T-U	138.00	69.00	12.00
28		T-U	161.00	138.00	11.00
29		T-U	138.00	34.00	
30		T-U	34.50	12.00	
31		T-U	69.00	34.00	2.50
32	JENKINS-PIKEVILLE	D-U	69.00	12.00	
33	MAYKING-PIKEVILLE	D-U	69.00	12.00	
34	ASHLAND-ASHLAND	D-U	69.00	12.00	
35	BAKER-LOUISA	T-U	765.00	345.00	34.50
36	BAKER	T-U	345.00	138.00	34.50
37		T-U	765.00		
38		T-U	69.00	34.50	
39		T-U	69.00	12.00	
40		T-U	34.50	7.20	

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BARRENSHE-FREEBURN	D-U	69.00	12.00	
2	BEAVER CREEK-CLEAR CR. JCT.	T-U	138.00	69.00	46.00
3		T-U	138.00	8.30	
4		T-U	46.00	0.48	
5		T-U	46.00		
6		T-U	69.00	12.00	
7	BECKHAM-HINDMAN	D-U	138.00	34.50	
8	BEEFHIDE-JENKINS	D-U	138.00	34.50	
9	BELFRY	D-U	46.00	12.00	
10	BELHAVEN-FLATWOODS	D-U	138.00	12.00	
11	BELLEFONTE-BELLEFONTE	T-U	138.00	34.50	
12		T-U	138.00	69.00	34.50
13		T-U	34.50	34.50	
14		T-U	34.50	2.50	
15		T-U	34.50		
16		T-U	138.00	12.00	
17	BETSY LAYNE-BETSY LAYNE	T-U	46.00	12.00	
18		T-U	138.00	34.00	
19		T-U	138.00	69.00	46.00
20		T-U	46.00	2.40	
21	BIG SANDY	T-A	138.00	34.50	
22		T-A	22.00	4.00	
23		T-A	138.00	13.80	
24		T-A	345.00	24.50	
25		T-A	138.00	23.00	
26		T-A	138.00	69.00	34.50
27		T-A	138.00	34.50	12.00
28		T-A	138.00	4.16	
29		T-A	4.00	0.60	
30		T-A	4.00	0.60	
31		T-A	13.80	4.00	
32		T-A	138.00	4.00	
33	BLUEGRASS	D-A	69.00	12.00	
34	BONNYMAN-BONNYMAN	T-U	69.00	34.50	
35	BUSSEYVILLE-BUSSEYVILLE	D-U	138.00	34.50	
36	CANNONSBURG-ASHLAND	D-U	69.00	34.50	
37	CEDAR CREEK-PIKEVILLE	T-U	138.00	69.00	46.00
38	CEDAR CREEK	T-U	46.00		
39		T-U	46.00	12.00	
40		T-U	34.50	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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		T-U	34.50	12.00	
2	CHADWICK-CHADWICKS CREEK	T-U	138.00	69.00	34.50
3	HAYWARD	D-U	69.00	12.00	
4	COALTON-COALTON	D-U	69.00	12.00	
5	HENRY CLAY-HELLIER	D-U	46.00	34.50	
6	HIGHLAND (KP)	D-U	69.00	12.00	
7	HITCHINS-HITCHINS	D-U	69.00	12.00	
8	HOWARD COLLINS-ASHLAND	D-U	69.00	12.00	
9	INEZ-INEZ	D-U	138.00	69.00	
10	INEZ	D-U	138.00	37.27	13.80
11		D-U	138.00	37.00	
12			56.00	18.60	
13		D-U	26.00		
14	JACKSON-JACKSON	T-U	69.00	12.00	
15	JOHNS CREEK-KIMPER	T-U	138.00	69.00	34.00
16		T-U	34.00		
17	KENWOOD-PAINTSVILLE	D-U	46.00	12.00	
18	KEYSER-KEYSER	D-U	69.00	12.00	
19	LESLIE-WOOTEN	T-U	161.00	69.00	12.00
20		T-U	69.00	34.00	12.00
21	LOUISA-LOUISA	D-U	34.50	12.00	
22	LOVELY-LOVELY	T-A	138.00	34.00	
23	MCKINNEY	D-U	46.00	34.00	
24		D-U	34.00	12.00	
25	MOBILE KP-2	D-U	69.00	12.00	
26	MOBILE KP-3	D-U	69.00	12.00	
27	MOBILE KP-5	D-U	69.00	34.50	
28	NEW CAMP	D-U	69.00	12.00	
29	OLIVE HILL	D-U	69.00	12.00	
30		D-U	69.00	4.00	
31	PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
32	PRINCESS-CANNONSBURG	D-U	69.00	34.50	
33	REEDY COAL	D-U	69.00	34.00	
34	RUSSELL-RUSSELL	D-U	69.00	12.00	
35	SIDNEY-SIDNEY	D-U	69.00	12.00	
36	SLEMP-SLEMP	D-U	69.00	34.00	
37		D-U	69.00	34.50	
38	SOUTH PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
39	STINNETT-HOSKINGSTON	D-U	161.00	34.00	7.20
40	STINNETT	D-U	161.00	34.50	7.20

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STONE-BELFRY	T-U	138.00	69.00	46.00
2		T-U	46.00	7.20	
3	TENTH STREET-ASHLAND	D-U	69.00	12.00	
4	THELMA-PAINTSVILLE	D-U	138.00	69.00	46.00
5		D-U	46.00	7.20	
6	TOM WATKINS	D-U	69.00	12.00	
7	TURKEY CREEK	D-U	69.00	46.00	
8	VICCO	D-U	138.00	34.50	
9	WEST PAINTSVILLE	D-U	69.00	12.00	
10	WHITEBURG	D-U	69.00	12.00	
11	WURTLAND	D-U	69.00	12.00	
12					
13	40 STATIONS UNDER 10,000 MVA	T/D			
14					
15					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)	
4	1					1
20	1					2
25	1		STAT CAP	1	10	3
90	1		STAT CAP	1	27	4
25	1					5
45	1					6
3	3					7
11	1					8
11	1					9
20	1					10
20	1					11
11	1					12
25	1		STAT CAP	1	11	13
20	1					14
20	1					15
20	1					16
22	1					17
130	1		STAT CAP	1	14	18
20	1					19
30	1					20
20	1					21
11	1					22
20	1					23
25	1					24
60	1					25
	1					26
180	2		STAT CAP	2	46	27
180	3	1				28
30	1					29
8	1					30
6	1					31
11	1					32
20	1					33
22	1		STAT CAP	1	16	34
1500	2	1	REACTOR	3	300	35
672	1					36
500	3		REACTOR	2	200	37
30		1				38
3		1				39
1	2					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.
25	1					1
146	2		STAT CAP	8	317	2
250	2		REACTOR	6	126	3
2	2					4
	2					5
5	1					6
25	1					7
20	1					8
11	1					9
20	1					10
45	1					11
308	2					12
4	4					13
	1					14
	1					15
22	1					16
6	1		STAT CAP	1	10	17
25	1					18
30	1					19
2	1					20
20	1					21
98	5					22
50	2					23
950	1					24
300	2					25
90	1					26
9	1					27
16	1					28
4	2					29
2	1					30
14	2					31
20	1					32
11	1					33
25	1					34
25	1					35
25	1					36
90	1					37
	1					38
4		1				39
2	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4	1	1				1
200	1					2
9	1					3
25	1		STAT CAP	1	14	4
30	1					5
13	1	1				6
10	2					7
29	2					8
50	1		STAT CAP	1	10	9
160	1					10
320	2					11
86	1					12
86	1					13
13	2		STAT CAP	1	5	14
90	1		STAT CAP	1	10	15
	1					16
20	1					17
20	1					18
90	1					19
20	1					20
10	2					21
30	1					22
20	1					23
7	1					24
10	1					25
14	1					26
15	1					27
20	1					28
8	1					29
5	1					30
25	1					31
20	1					32
20	1					33
22	1					34
20	1					35
20	1					36
11	1					37
25	1					38
15	1					39
22	1					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
	1					2
22	1					3
50	1					4
2	1					5
11	1					6
10	1					7
30	1					8
20	1					9
20	2					10
20	1					11
						12
178	40					13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
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						28
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