CASE NUMBER:

99-149

STITES & HARBISON

ATTORNEYS

May 7, 1999

RECEIVED
MAY 07 1999
PUBLIC SERVICE COMMISSION

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com
Mark R. Overstreet
[502] 223-3477 Ext. 219
moverstreet@stites.com

Ms. Helen Helton
Executive Director
Public Service Commission of Kentucky
P.O. Box 615
Frankfort, KY 40602-0615

Case No. 99-149

RE: In the Matter of Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and South West Corporation, P.S.C. Case No. 149

Dear Ms. Helton:

Please accept for filing nine copies of the Joint Applicants' Supplemental Response to Item 3 of Staff's April 22, 1999 Informal Conference Data Request. It is Kentucky Power Company's 1998 FERC Form 1, which was not available at the time the original response was filed and served.

The number of copies provided is in accordance with Staff's oral directions at the Informal Conference. Copies of the Supplemental Response previously were provided to the other parties at the May 4, 1999 Informal Conference.

Very truly yours,

Mark R. Overstreet

cc: William H. Jones, Jr.
Elizabeth E. Blackford
James W. Brew
Richard S. Taylor
David F. Boehm

KE057:KE131:2106:FRANKFORT

KENTUCKY POWER COMPANY
d/b/a

AMERICAN ELECTRIC POWER
KPSC CASE NO. 99-149
Item No. 3

SUPPLEMENTAL RESPONSE TO DATA REQUEST(TC-1st Set)
KENTUCKY PUBLIC SERVICE COMMISSION
ORDER DATED APRIL 22, 1999

RECEIVED
MAY 07 1999
PUBLIC SERVICE
COMMISSION

KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Please provide a copy of Kentucky Power Company's 1996-1998 FERC Form 1.

SUPPLEMENTAL RESPONSE:

Attached please find a copy of the 1998 FERC Form 1 for Kentucky Power Company.

RECEIVED
MAY 07 1999
PUBLIC SERVICE
COMMISSION

WITNESS: RICHARD E. MUNCZINSKI

THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____
Item 2: [ ] An Original Signed Form	OR [✓] Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 11/30/2001)

DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. 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 this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
KENTUCKY POWER COMPANY	Dec. 31, 1998

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, Licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

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 this form.

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

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

III. What and Where to Submit

(a) Submit this form on electronic media consisting of two (2) duplicate data diskettes and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription staging that the paper copies contain the same information as contained on the electronic media, that the signer knows the contents of the paper copies and electronic media, and that the contents as stated in the copies and on the electronic media are true to the-best knowledge and belief of the signer.

(b) 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 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:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21 Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, 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) Signed by independent cestified 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 41.'10-41.12 for specific qualifications).

III. What and Where to Submit (Continued)

Attachment
Page 3 of 210
KPSC Case No. 99-149
TC (1st Set)
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(c) Continued

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

When accompanying this form, 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 office of the Secretary at the address indicated at III (a).

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-1 ED-12.2
Washington, DC 20426
(202) 208-2474

IV. When to Submit

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for this collection of information is estimated to average 1,217 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. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street ME., Washington, DC 20426 (Attention: Mr. Michael Hitter, ED-12.3); 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).

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 year, and use for statement of income accounts the current year's amounts.

III Complete each question fully and accurately, even if it has been answered in a previous annual 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, 3, and 4.

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). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

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, two (2) new data diskettes and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a) must be filed. Resubmissions must be numbered sequentially both on the diskettes and on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

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

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

Definitions

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

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

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EXCERPTS FROM THE LAW

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

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to 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 the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission 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."

"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 filed..."

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:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent KENTUCKY POWER COMPANY		02 Year of Report Dec. 31, 1998
03 Previous Name and Date of Change *(if name changed during year)* / /		
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Geoffrey C. Dean		06 Title of Contact Person Director Financial Reporting
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, OH 43215		
08 Telephone of Contact Person, *Including Area Code* (614) 223-2780	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/30/1999
ATTESTATION		
The undersigned officer certifies that he/she has examined the accompanying report: that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.		
01 Name Gerald R. Knorr 02 Title Assistant Controller	03 Signature Gerald R. Knorr	04 Date Signed *(Mo, Da, Yr)* 04/23/1999
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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".

Attachment
Page 7 of 210
KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
38	Taxes Accrued, Prepaid and Charged During the Year	262-263	
39	Accumulated Deferred Investment Tax Credits	266-267	
40	Other Deferred Credits	269	
41	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
42	Accumulated Deferred Income Taxes-Other Property	274-275	
43	Accumulated Deferred Income Taxes-Other	276-277	
44	Other Regulatory Liabilities	278	
45	Electric Operating Revenues	300-301	
46	Sales of Electricity by Rate Schedules	304	
47	Sales for Resale	310-311	
48	Electric Operation and Maintenance Expenses	320-323	
49	Number of Electric Department Employees	323	
50	Purchased Power	326-327	
51	Transmission of Electricity for Others	328-330	
52	Transmission of Electricity by Others	332	
53	Miscellaneous General Expenses-Electric	335	
54	Depreciation and Amortization of Electric Plant	336-337	
55	Particulars Concerning Certain Income Deduction and Int Charges Accnts	340	
56	Regulatory Commission Expenses	350-351	
57	Research, Development and Demonstration Activities	352-353	
58	Distribution of Salaries and Wages	354-355	
59	Common Utility Plant and Expenses	356	N/A
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
63	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	N/A
64	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	N/A
65	Generating Plant Statistics (Small Plants)	410-411	N/A
66	Transmission Line Statistics	422-423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During Year	424-425	N/A
68	Substations	426-427	
69	Electric Distribution Meters and Line Transformers	429	
70	Environmental Protection Facilities	430	
71	Environmental Protection Expenses	431	
72	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 of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

Leonard V. Assante, Controller and Chief Accounting Officer
1 Riverside Plaza
Columbus, OH 43215-2373

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

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 principle 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 of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

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(Next Page is 104)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 attached page included in filed copies only.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	E. Linn Draper, Jr., Chairman of the Board and Chief	Columbus, OH
2	Executive Officer	
3		
4	W. J. Lhota, President and Chief Operating Officer	Columbus, OH
5		
6	P. J. DeMaria, Vice President and Controller	Columbus, OH
7		
8	G. P. Maloney, Vice President	Columbus, OH
9		
10	J. J. Markowsky, Vice President	Columbus, OH
11		
12	J. H. Vipperman, Vice President	Columbus, OH
13		
14	H. W. Fayne, Vice President	Columbus, OH
15		
16	A. A. Pena, Vice President, Treasurer, and Chief Financial	Columbus, OH
17	Officer	
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21	(A) Company does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust(whether voting trust, etc.) duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a List of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights give other important particulars (details) concerning voting rights of such security. State whether voting right are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method explain briefly in a footnote.
4. Furnish particulars (details) concerning any options warrants, or rights outstanding at the end of the year others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or right the amount of such securities or assets so entitled to purchased by any officer, director, associated company, or of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the public where the options, warrants, or rights were issued prorata basis.

1. Give the date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors of the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting
Stock book does not close	Total: 1,009,000 By Proxy: 1,009,000	May 11, 1998 Columbus, OH

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of Votes as of (date): 12/31/1998 — Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1,009,000	1,009,000		
5	TOTAL number of security holders	1	1		
6	TOTAL votes of security holders listed below	1,009,000	1,009,000		
7	American Electric Power Company, Inc.				
8	1 Riverside Plaza				
9	Columbus, OH 43215	1,009,000	1,009,000		
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11					
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Attachment
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KPSC Case No. 99-149
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Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

IMPORTANT CHANGES DURING THE 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

IMPORTANT CHANGES DURING THE YEAR (continued)

Kentucky Power Company

1. The following franchise rights secured as original franchise or an extension of present rights:

Date Acquired	Acquired From	Period	Consideration
07/14/98	South Shore, KY	20 years	25% of street lighting payment

2. None

3. None

4. None

5. None

6. SEC File No. 333-35767 under the Securities Act of 1933; Kentucky Public Service Commission Case No. CF-KP-95-401:

$30,000,000 6.45% Unsecured Medium Term Notes, Series A due 2008

SEC File No. 70-8693 under the Public Utility Holding Company Act of 1935. Short-term borrowing authority not to exceed $150,000,000 through December 31, 2003.

7. None

8. The 1998 wage agreement resulted in a general increase of 3.0% for represented employees.

9. On April 24, 1996, the FERC issued orders 888 and 889. These orders require each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an Open Access Same-time Information System ("OASIS") which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct which prohibit utilities' system operators from providing non-public transmission information to the utility's merchant employees. The orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

On July 9, 1996, the American Electric Power Company, Inc. (AEP) System companies filed a tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues, which are still pending before FERC.

During 1996 and 1997 AEP engaged in discussions with several utilities regarding the creation of an independent system operator to operate the transmission system in the Midwestern region of the United States. In January 1998, nine utilities or utility systems filed with the FERC a proposal to form the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). AEP was not a participant in that filing and elected not to join the Midwest ISO as a transmission owner member. AEP has since joined the Midwest ISO as a non-owner member.

During the 1998 Regular Session of the Kentucky legislature, the Electric Utility Restructuring Task Force was established by resolution. The 20-member Task Force includes ten members of the General Assembly and ten officials from the Governor's office. The Task Force began monthly meetings in August 1998. At the January

1999 meeting, AEP, the other Kentucky investor-owned public utilities and the Kentucky electric cooperatives were requested to file with the Task Force a description of their non-traditional, unregulated businesses. The final report of the Task Force is due in November 1999, prior to the next regularly scheduled legislative session in 2000.

A second Task Force was also established to study the effects of utility restructuring on taxes. This Task Force also has been meeting monthly and will report its findings in November 1999. Several advisory committees have been formed to assist this Task Force in gathering and studying information. The Kentucky investor-owned utilities, including AEP, are represented on each of those committees. At the January meeting, the Task Force voted to retain a consulting firm with extensive experience in utility tax issues to facilitate the proceedings.

The Kentucky Public Service Commission Chairwoman leads 23 state public utility commissions in a coalition entitled Low Cost States Initiative. The coalition's stated purpose is to ensure that the U.S. Congress gives equal consideration to the issues facing low-cost states. The coalition is focusing on the following five issues: (i) a National Voice, (ii) Low Rates, (iii) Rural Electricity Rates, (iv) Stranded Costs and Benefits, and (v) Economic Development.

During the week of June 22-26, 1998, wholesale electric power markets in the Midwest exhibited unprecedented price volatility due to several market factors, including an extended period of unseasonably hot weather, scheduled and unplanned generating unit outages, transmission constraints, and defaults by certain power marketers on their supply obligations. The simultaneous culmination of these events resulted in temporary but extreme price spikes in the hourly and daily markets.

As a result of this situation, the FERC initiated an investigations into the price increase. After completing its review, the FERC concluded that the pricing abnormalities were due to the unusual conditions that occurred during that time. The FERC Staff report issued in September 1998 did not find evidence that firm service to consumers was compromised anywhere in the Midwest during the period of the pricing abnormalities. The FERC reserved the right to conduct further investigations on a company-specific basis.

The Acid Rain Program (Title IV) of the Clean Air Act Amendments of 1990 (CAAA) created an emission allowance program pursuant to which utilities are authorized to emit a designated quantity of sulfur dioxide (SO2), measured in tons per year, on a system wide or aggregate basis. Emission reductions are required by virtue of the establishment of annual allowance allocations at levels substantially below historical emission levels for most utility units. There are two phases of SO2 control under the Acid Rain Program. Phase I, effective January 1, 1995, requires SO2 emission reductions from certain units that emitted SO2 above a rate of 2.5 pounds per million Btu heat input in 1985. Phase I unit allowance allocations were calculated based on 1985 utilization rates and an emission rate of 2.5 pounds of SO2 per million Btu heat input. Phase I permits have been issued for all Phase I affected units in the AEP System.

Phase II, which affects all fossil fuel-fired steam generating units with capacity greater than 25 megawatts imposes more stringent SO2 emission control requirements beginning January 1, 2000. If a unit emitted SO2 in 1985 at a rate in excess of 1.2 pounds per million Btu heat input, the Phase II allowance allocation is premised upon an emission rate of 1.2 pounds at 1985 utilization levels. If actual SO2 emissions for a Phase II affected unit in 1985 were less than 1.2 pounds per million Btu, the allowance allocation is, in most instances, based on the actual 1985 emission rate.

In addition to regulating SO2 emissions, Title IV of the CAAA contains provisions regulating emissions of nitrogen oxides (NOx). In April 1995, Federal EPA promulgated NOx emission limitations for tangentially fired boilers and dry bottom wall-fired boilers for Phase I and Phase II units. In addition, on December 19, 1996, Federal EPA published final NOx emission limitations for wet bottom wall-fired boilers, cyclone boilers, units applying cell burner technology and all other types of boilers. The regulations also revised downward the NOx limitations applicable to tangentially fired and wall-fired boilers in Phase II. These emission limitations are to be achieved by January 1, 2000.

The CAA contains additional provisions, other than the Acid Rain Program, which could require reductions in emissions of NOx and other pollutants from fossil fuel-fired power plants. In July 1997, Federal EPA revised the ozone and particulate matter National Ambient Air Quality Standards (NAAQS), creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns in diameter (PM2.5). Both of these new standards have the potential to affect adversely the operation of AEP System generating units. Substantial reductions in NOx emissions from fossil fuel-fired power plants may be required as part of a state's plan to attain the eight-hour ozone standard. The actual implementation of the new PM2.5 NAAQS has been delayed for five years. Substantial reductions in SO2 and/or other emissions from fossil fuel-fired power plants may be required as part of a state's plan to attain the PM2.5 NAAQS. In August and September 1997 the AEP System operating companies joined with certain other utilities to appeal the revised NAAQS by filing petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was held in December 1998.

In September 1998, Federal EPA issued revisions to the New Source Performance Standards applicable to new and modified fossil fuel-fired power plants. Federal EPA characterized its proposal as "fuel neutral" since it would impose the same stringent NOx emission limit (1.35lb. per megawatt-hour net energy output) for coal-fired boilers as for gas-fired boilers. The emission limit is set at a level which cannot currently be achieved by combustion controls and will require the use of post combustion control equipment. The final rule effectively requires selective catalytic reduction or comparable technology to control NOx emissions from new or modified coal-fired boilers. Imposition of this standard to existing sources which might become subject to the rule based on an administrative finding that an existing source had been modified or reconstructed could result in substantial capital and operating expenditures. On October 30, 1998, the AEP System operating companies joined with certain other utilities to appeal the revised regulations by filing petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit.

On October 27, 1998, Federal EPA published in the Federal Register a final rule (NOx transport SIP call) concluding that certain State Implementation Plans are deficient because they allow NOx emissions that contribute excessively to ozone nonattainment in downwind states. Federal EPA's NOx transport SIP call establishes state-by-state NOx emission budgets for the five-month ozone season to be met by the year 2003. The NOx budgets apply to 22 eastern states and are premised mainly on the assumption of controlling power plant NOx emissions to 0.15 lb. per million Btu (approximately 85% below 1990 levels). The NOx transport SIP call purports to implement both the new eight-hour ozone standard and the one-hour ozone standard. The SIP call was accompanied by a proposed Federal Implementation Plan which could be implemented in any state which fails to submit an approvable SIP by September 1999. The NOx reductions called for by Federal EPA are targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to obtain new and modified source permits. In October 1998, the AEP System operating companies joined with certain other utilities to appeal the final NOx SIP Call rule by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit.

Preliminary estimates indicate that compliance costs could result in $105 million of required capital expenditures. Compliance costs cannot be estimated with certainty and the actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions.

In August 1997, eight northeastern states (New York, New Hampshire, Maine, Massachusetts, Rhode Island, Pennsylvania, Connecticut, and Vermont) filed petitions with Federal EPA under Section 126 of the Clean Air Act, claiming that NOx emissions from certain named sources in midwestern states, including all the coal-fired plants of AEP's operating subsidiaries, prevent those states from attaining the ozone NAAQS. Among other things, the petitioners generally seek NOx emission reductions 85% below 1990 levels from the utility sources in midwestern states, as in the NOx SIP call. On October 21, 1998, Federal EPA published in the Federal Register proposed conditional remedial action requiring NOx emission reductions from named utility sources.

Federal EPA is seeking comment on the effect on the Section 126 petitions of a proposed determination by Federal EPA that the one-hour ozone standard no longer applies to non-attainment areas in Maine, New Hampshire, Rhode Island and a portion of Massachusetts. In a separate Notice of Proposed Rulemaking, Federal EPA is seeking comment with respect to its proposed determination that eight-hour ozone non-attainment in New Hampshire and Maine is being significantly affected by sources of NOx emissions in the northeastern U.S. as well as certain sources in the midwestern and southern U.S.

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In December 1997 Federal EPA entered into a Memorandum of Agreement (MOA) with the petitioning states that establishes a schedule for taking final action on the Section 126 petitions on approximately the same time frame as Federal EPA's final action on the NOx transport SIP call. The MOA called for a proposed rulemaking on the Section 126 petitions by September 30, 1998 and a technical determination by April 30, 1999. Final action would be deferred pending satisfaction of the NOx SIP call requirements. In October 1998, the U.S. District Court for the Southern District of New York entered an order directing Federal EPA to conform to the schedule set forth in the MOA.

Hazardous air pollutant emissions from utility boilers are potentially subject to control requirements under Title III of the CAAA. The CAAA specifically directed Federal EPA to study potential public health impacts of hazardous air pollutants emitted from electric utility steam generating units. Federal EPA was required to report the results of this study to Congress by November 1993 and to regulate emissions of these hazardous pollutants if necessary. On February 25, 1998, Federal EPA issued a final report to Congress citing as potential health and environmental threats, mercury and three other hazardous air pollutants present in power plant emissions. Noting uncertainty regarding health effects and the absence of control technology for mercury, no immediate regulatory action was proposed regarding emission reductions.

In addition, Federal EPA is required to study the deposition of hazardous pollutants in the Great Lakes, the Chesapeake Bay, Lake Champlain, and other coastal waters. As part of this assessment, Federal EPA is authorized to adopt regulations to prevent serious adverse effects to public health and serious or widespread environmental effects. It is possible that this assessment of water body deposition may result in additional regulation of electric utility steam generating units.

Federal EPA was also required to study mercury emissions and report its findings to Congress by 1994. Federal EPA presented that report to Congress in December 1997. The report identifies electric utilities as being the third leading emitter of mercury. Presently, mercury emissions from electric utilities are not regulated under the CAA. However, Federal EPA intends to engage in further studies of mercury emissions, which may lead to additional regulation in the future.

The CAAA expanded the enforcement authority of the federal government by increasing the range of civil and criminal penalties for violations of the CAA and enhancing administrative civil provisions, adding a citizen suit provision and imposing a national operating permit system, emission fee program and enhanced monitoring, recordkeeping and reporting requirements for existing and new sources. On February 13, 1997, Federal EPA issued the Credible Evidence rule, which allows Federal EPA to use any credible evidence or information in lieu of, or in addition to, the test methods prescribed by the regulation for determining compliance with emission limits. This rule has the potential to expand significantly Federal EPA's ability to bring enforcement actions and to increase the stringency of the emission limits to which AEP System plants are subject. In March 1997, a number of industries, including AEP System operating companies, filed petitions for review of the Credible Evidence Rule with the U.S. Court of Appeals for the District of Columbia Circuit. In August 1998, the court held that the appeal was not ripe for review. A petition for writ of certiori was filed with the U.S. Supreme Court.

In December 1997, delegates from 167 nations, including the United States, agreed to a treaty, known as the "Kyoto Protocol," establishing legally-binding emission reductions for gases suspected of causing climate change. If the U.S. becomes a party to the treaty it will be bound to reduce emissions of carbon dioxide (CO_2), methane and nitrous oxides by 7% below 1990 levels and emissions of hydrofluorcarbons, perfluorocarbons and sulphur hexafluoride 7% below 1995 levels in the years 2008-2012. The Protocol was available for signature from March 16, 1998 to March 15, 1999 and requires ratification by at least 55 nations that account for at least 55% of developed countries' 1990 emissions of CO_2 to enter into force.

Although the United States has agreed to the treaty and signed it on November 12, 1998, President Clinton has indicated that he will not submit the treaty to the Senate for ratification until it contains requirements for "meaningful participation by key developing countries" and the rules, procedures, methodology and guidelines of the treaty's market-based policy instruments, joint implementation programs and compliance enforcement provisions have been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view

IMPORTANT CHANGES DURING THE YEAR (continued)

toward approving them at the Sixth Conference of the Parties to be held in December 2000.

On January 2, 1997, Federal EPA proposed a new intervention level program under the authority of Section 303 of the CAA to address five minute peak SO2 concentrations believed to pose a health risk to certain segments of the population. The proposal establishes a "concern" level and an "endangerment" level. States must investigate exceedances of the concern level and decide whether to take corrective action. If the endangerment level is exceeded, the state must take action to reduce SO2 levels.

On July 31, 1997, Federal EPA proposed new rules to regulate regional haze attributable to anthropogenic emissions. The primary goal of the new regional haze program is to address visibility impairment in and around "Class I" protected areas, such as national parks and wilderness areas. Because regional haze precursor emissions are believed by Federal EPA to travel long distances, Federal EPA proposes to regulate such precursor emissions in every state. Under the proposal, each state must develop a regional haze control program that imposes controls necessary to steadily reduce visibility impairment in Class I areas on the worst days and that ensures that visibility remains good on the best days.

On July 21, 1992, Federal EPA published final regulations in the Federal Register governing application of new source rules to generating plant repairs and pollution control projects undertaken to comply with the CAA. Generally, the rule provides that plants undertaking pollution control projects will not trigger New Source Review requirements. The Natural Resources Defense Council and a group of utilities, including five AEP System companies, have filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the regulations. In July 1998, Federal EPA requested comment on proposed revisions to the New Source Review rules which would change New Source Review applicability criteria by eliminating exemptions contained in the current regulation.

Federal EPA conducted a review of the accounting records of KEPCo in the summer of 1998. This activity is focused on assessing compliance with the New Source Review and New Source Performance Standard provisions of the Clean Air Act.

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and similar state law provide governmental agencies with the authority to require clean-up of hazardous waste sites and releases of hazardous substances into the environment and to seek compensation for damages to natural resources. Since liability under CERCLA is strict and can be applied retroactively, AEP System companies which previously disposed of PCB-containing electrical equipment and other hazardous substances may be required to participate in remedial activities at such disposal sites should environmental problems result. Kentucky Power Company, Inc. (KEPCo) has been named as a potentially responsible party at one federal remediation site. KEPCo's share of clean-up costs, however, is not expected to be significant.

10. None

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	966,806,725	1,003,849,892
3	Construction Work in Progress (107)	200-201	32,059,799	30,075,995
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		998,866,524	1,033,925,887
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	288,229,516	305,760,505
6	Net Utility Plant (Enter Total of line 4 less 5)		710,637,008	728,165,382
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		710,637,008	728,165,382
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	973,644	1,039,057
15	(Less) Accum. Prov. for Depr. and Amort. (122)		159,168	165,828
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	0	0
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		5,768,572	11,204,307
21	Special Funds (125-128)		8,528	0
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		6,591,576	12,077,536
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		1,217,448	1,062,314
25	Special Deposits (132-134)		109,558	828,494
26	Working Fund (135)		54,114	44,369
27	Temporary Cash Investments (136)		0	0
28	Notes Receivable (141)		0	0
29	Customer Accounts Receivable (142)		24,127,289	23,294,531
30	Other Accounts Receivable (143)		2,529,668	2,580,348
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		524,659	847,677
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		1,722,195	8,796,843
34	Fuel Stock (151)	227	10,379,192	7,635,967
35	Fuel Stock Expenses Undistributed (152)	227	306,130	251,860
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	7,752,082	6,315,445
38	Merchandise (155)	227	0	0
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	6,152,259	7,336,924
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	149,395	0
44	Gas Stored Underground - Current (164.1)		0	0
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		1,447,743	1,581,935
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		0	0
49	Rents Receivable (172)		746,621	1,438,367
50	Accrued Utility Revenues (173)		12,980,999	13,560,119
51	Miscellaneous Current and Accrued Assets (174)		89,019	4,801,086
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		69,239,053	78,680,925

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	**DEFERRED DEBITS**			
54	Unamortized Debt Expenses (181)		626,127	600,635
55	Extraordinary Property Losses (182.1)	230	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
57	Other Regulatory Assets (182.3)	232	106,892,346	106,643,414
58	Prelim. Survey and Investigation Charges (Electric) (183)		3,871,606	3,871,606
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
60	Clearing Accounts (184)		88,010	-12,394
61	Temporary Facilities (185)		0	354
62	Miscellaneous Deferred Debits (186)	233	5,573,320	6,015,809
63	Def. Losses from Disposition of Utility Plt. (187)		0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reaquired Debt (189)		756,855	620,691
66	Accumulated Deferred Income Taxes (190)	234	34,276,230	31,453,160
67	Unrecovered Purchased Gas Costs (191)		0	0
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		152,084,494	149,193,275
69	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,52,68)		938,552,131	968,117,118

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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (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	128,750,000	148,750,000
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	78,076,120	71,451,987
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		257,276,120	270,651,987
15	**LONG-TERM DEBT**			
16	Bonds (221)	256-257	220,000,000	217,797,000
17	(Less) Reaquired Bonds (222)	256-257	0	0
18	Advances from Associated Companies (223)	256-257	0	0
19	Other Long-Term Debt (224)	256-257	123,000,000	153,000,000
20	Unamortized Premium on Long-Term Debt (225)		0	0
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,949,512	1,959,094
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		341,050,488	368,837,906
23	**OTHER NONCURRENT LIABILITIES**			
24	Obligations Under Capital Leases - Noncurrent (227)		15,006,077	14,957,058
25	Accumulated Provision for Property Insurance (228.1)		0	0
26	Accumulated Provision for Injuries and Damages (228.2)		3,117,807	2,626,127
27	Accumulated Provision for Pensions and Benefits (228.3)		8,569,346	9,243,572
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
29	Accumulated Provision for Rate Refunds (229)		0	0
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		26,693,230	26,826,757
31	**CURRENT AND ACCRUED LIABILITIES**			
32	Notes Payable (231)		36,500,000	20,350,000
33	Accounts Payable (232)		13,841,921	12,917,041
34	Notes Payable to Associated Companies (233)		0	0
35	Accounts Payable to Associated Companies (234)		10,732,586	11,813,625
36	Customer Deposits (235)		3,660,023	4,037,872
37	Taxes Accrued (236)	262-263	6,129,640	7,255,946
38	Interest Accrued (237)		6,015,232	6,241,355
39	Dividends Declared (238)		0	0
40	Matured Long-Term Debt (239)		0	0
41	Matured Interest (240)		0	0
42	Tax Collections Payable (241)		2,091,410	1,934,765
43	Miscellaneous Current and Accrued Liabilities (242)		9,124,580	12,746,513
44	Obligations Under Capital Leases-Current (243)		3,719,047	4,019,780
45	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		91,814,439	81,316,897

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	**DEFERRED CREDITS**			
47	Customer Advances for Construction (252)		222,840	211,553
48	Accumulated Deferred Investment Tax Credits (255)	266-267	15,614,829	14,199,899
49	Deferred Gains from Disposition of Utility Plant (256)		0	0
50	Other Deferred Credits (253)	269	173,691	1,106,143
51	Other Regulatory Liabilities (254)	278	17,485,182	14,806,516
52	Unamortized Gain on Reaquired Debt (257)		0	0
53	Accumulated Deferred Income Taxes (281-283)	272-277	188,221,312	190,159,460
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		221,717,854	220,483,571
55			0	0
56			0	0
57			0	0
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		938,552,131	968,117,118

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STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	362,998,624	359,543,349
3	Operating Expenses			
4	Operation Expenses (401)	320-323	233,138,931	242,579,173
5	Maintenance Expenses (402)	320-323	30,462,186	24,416,844
6	Depreciation Expense (403)	336-337	28,038,044	26,247,598
7	Amort. & Depl. of Utility Plant (404-405)	336-337	3,701	187,562
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	7,286,699	7,122,376
14	Income Taxes - Federal (409.1)	262-263	8,386,861	10,425,322
15	- Other (409.1)	262-263	2,400,733	2,274,411
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	18,755,893	15,639,772
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	14,789,196	14,979,754
18	Investment Tax Credit Adj. - Net (411.4)	266	-1,202,148	-1,219,380
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)		1,414,241	45,281
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		311,106,079	312,687,259
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		51,892,545	46,856,090

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STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.

8. Enter on pages 122-123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages.122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
362,998,624	359,543,349					2
						3
233,138,931	242,579,173					4
30,462,186	24,416,844					5
28,038,044	26,247,598					6
3,701	187,562					7
38,616	38,616					8
						9
						10
						11
						12
7,286,699	7,122,376					13
8,386,861	10,425,322					14
2,400,733	2,274,411					15
18,755,893	15,639,772					16
14,789,196	14,979,754					17
-1,202,148	-1,219,380					18
						19
						20
1,414,241	45,281					21
						22
311,106,079	312,687,259					23
51,892,545	46,856,090					24

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STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		51,892,545	46,856,090
26	Other Income and Deductions			
27	Other Income			
28	Nonutilty Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		9,755	
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		43,086	24,237
31	Revenues From Nonutility Operations (417)			
32	(Less) Expenses of Nonutility Operations (417.1)			
33	Nonoperating Rental Income (418)		93,458	53,679
34	Equity in Earnings of Subsidiary Companies (418.1)	119		
35	Interest and Dividend Income (419)		144,053	121,665
36	Allowance for Other Funds Used During Construction (419.1)			45,067
37	Miscellaneous Nonoperating Income (421)		79,769,738	30,812
38	Gain on Disposition of Property (421.1)			2,760
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		79,973,918	229,746
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		22,198	
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	83,321,080	1,199,895
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		83,343,278	1,199,895
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	27,900	30,000
47	Income Taxes-Federal (409.2)	262-263	-793,963	-359,119
48	Income Taxes-Other (409.2)	262-263	-305,152	-84,650
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	228,608	316,095
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	588,631	235,260
51	Investment Tax Credit Adj.-Net (411.5)		-212,564	-172,915
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		-1,643,802	-505,849
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		-1,725,558	-464,300
55	Interest Charges			
56	Interest on Long-Term Debt (427)		26,123,660	23,463,456
57	Amort. of Debt Disc. and Expense (428)		271,812	239,113
58	Amortization of Loss on Reaquired Debt (428.1)		136,164	118,564
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340	2,681,172	3,235,475
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		721,676	1,410,554
64	Net Interest Charges (Enter Total of lines 56 thru 63)		28,491,132	25,646,054
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		21,675,855	20,745,736
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		21,675,855	20,745,736

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STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained eamings, unappropriated retained eamings, and unappropriated undistributed subsidiary eamings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained eamings.
4. List first account 439, Adjustments to Retained Eamings, reflecting adjustments to the opening balance of retained eamings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Eamings.
7. 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.
8. 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)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		78,076,120
2	Changes		
3	Adjustments to Retained Eamings (Account 439)		
4			
5			
6			
7			
8			
9	TOTAL Credits to Retained Eamings (Acct. 439)		
10			
11			
12			
13			
14			
15	TOTAL Debits to Retained Eamings (Acct. 439)		
16	Balance Transferred from Income (Account 433 less Account 418.1)		21,675,855
17	Appropriations of Retained Eamings (Acct. 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Eamings (Acct. 436)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		
30	Dividends Declared-Common Stock (Account 438)		
31	Common Stock	238	-28,299,988
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-28,299,988
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Eamings		
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		71,451,987
	APPROPRIATED RETAINED EARNINGS (Account 215)		

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STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. 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)	Amount (c)
39			
40			
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 (Account 215, 215.1, 216) (Total 38, 47)		71,451,987
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
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)		

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STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
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 on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	21,675,855
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	28,092,757
5	Amortization of	
6		
7		
8	Deferred Income Taxes (Net)	3,606,892
9	Investment Tax Credit Adjustment (Net)	-1,414,930
10	Net (Increase) Decrease in Receivables	-6,661,298
11	Net (Increase) Decrease in Inventory	3,198,862
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,652,458
14	Net (Increase) Decrease in Other Regulatory Assets	
15	Net Increase (Decrease) in Other Regulatory Liabilities	
16	(Less) Allowance for Other Funds Used During Construction	
17	(Less) Undistributed Earnings from Subsidiary Companies	
18	Other:	
19	Accrued Utility Revenues	-579,120
20	Payment of Disputed Tax and Interest Related to COLI	-5,376,525
21	Other Operating Items (Net)	-7,034,738
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	41,160,213
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-43,768,794
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	
31	Other:	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-43,768,794
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
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)	

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STATEMENT OF CASH FLOWS

4. Investing Activities include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.

5. Codes used:

(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
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	
54		
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	-43,768,794
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	30,000,000
62	Preferred Stock	
63	Common Stock	
64	Issuance Costs related to Long-Term Debt	-184,374
65	Capital Contributions From Parent Company	20,000,000
66	Net Increase in Short-Term Debt (c)	
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	49,815,626
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	-2,203,000
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	-16,150,000
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	-28,299,988
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	3,162,638
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	554,057
87		
88	Cash and Cash Equivalents at Beginning of Year	1,381,120
89		
90	Cash and Cash Equivalents at End of Year	1,935,177

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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 Commission 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.

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

NOTES TO FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Kentucky Power Company (the Company or KPCo) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. KPCo is engaged in the generation, purchase, sale, transmission and distribution of electric power serving 170,000 retail customers in eastern Kentucky and does business as American Electric Power (AEP). The Company supplies electric power to the AEP System Power Pool (AEP Power Pool) and shares the revenues and costs of Power Pool wholesale sales to neighboring utility systems and power marketers. The Company also sells wholesale power to municipalities. As a member of the AEP Power Pool and a signatory company to the American Electric Power System (AEP System) Transmission Equalization Agreement, the Company's generating and transmission facilities are operated in conjunction with the facilities of certain other AEP affiliated utilities as an integrated utility system.

Regulation

As a subsidiary of AEP Co., Inc., the Company is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Kentucky Public Service Commission (KPSC). The Federal Energy Regulatory Commission (FERC) regulates the Company's wholesale rates.

Basis of Accounting

The accounting of the Company 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 accounting requirements of the uniform system of accounts prescribed by the FERC. The principal differences from generally accepted accounting principles include the exclusion of current maturities of long-term debt from current liabilities, the exclusion of comparative statements of retained earnings and cash flows and the requirement to report deferred tax assets and liabilities separately rather than as a single amount.

As a cost-based rate-regulated entity, KPCo's financial statements reflect the actions of regulators that may result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric utility plant in service account and deducted from accumulated depreciation together with associated removal costs, net of salvage. The costs of labor, materials and overheads incurred to operate and maintain utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1998 and 1997 were not significant.

Depreciation and Amortization

Depreciation is provided on a straight-line basis over the estimated useful lives of property and is calculated largely through the use of composite rates by functional class. The annual composite depreciation rates for 1998 and 1997 were as follows:

Functional Class of Property	Annual Composite Depreciation Rates
Production	3.8%
Transmission	1.7%
Distribution	3.5%
General	2.5%

Expenditures for the demolition and removal of plant are charged to the accumulated provision for depreciation and recovered through depreciation charges included in rates.

Cash and Cash Equivalents

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

Operating Revenues and Fuel Cost

Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Changes in retail jurisdictional fuel costs are deferred until reflected in billings to customers in later months through a fuel cost recovery mechanism. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Derivative Financial Instruments

During 1998, the AEP Power Pool substantially increased the volume of its power marketing and trading transactions (trading activities) in which the Company shares. Trading activities involve the sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures

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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. For 1998, the net revenues from these transactions are included in operating revenues for ratemaking, accounting and financial and regulatory reporting purposes.

In addition the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area. These non-regulated trading activities are included in nonoperating income and accounted for on a mark-to-market basis. The unrealized mark-to-market gains and losses from such non-regulated trading activity are reported as assets and liabilities, respectively.

The Company enters into forward contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Any resultant gains or losses are deferred and amortized over the life of the debt issuance. There were no such forward contracts outstanding at December 31, 1998 or 1997.

See Note 5 - Financial Instruments, Credit and Risk Management for further discussion.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in rates, deferred income taxes are recorded with related regulatory assets and liabilities in accordance with SFAS 71.

Investment Tax Credits

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 regulated plant investment.

Debt

Gains and losses on reacquisition of debt are deferred and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If debt is refinanced, reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

Debt discount or premium and expenses of debt issuance are amortized over the term of the related debt, with the amortization included in interest charges.

Other Property and Investments

Other property and investments are stated at cost.

Comprehensive Income

There were no material differences between net income and comprehensive income.

2. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations. Such commitments do not include any expenditures for new generating capacity. Construction expenditures for 1999-2001 are estimated to be $112 million.

Long-term fuel supply contracts generally contain clauses that provide for periodic price adjustments. The contracts are for various terms, the longest of which extends to the year 2001 and contain various clauses that would release the Company from its obligation under certain force majeure conditions. A KPSC fuel adjustment mechanism generally provides for recovery of changes in the cost of fuel.

A constructive marketing program enables residential customers to borrow from area banks to purchase energy efficient electrical equipment, such as heat pumps. KPCo guarantees the loan principal plus interest. The guaranteed amounts totaled $7 million at December 31, 1998.

Clean Air Act/Air Quality

The US Environmental Protection Agency (Federal EPA) is required by the Clean Air Act Amendments of 1990 (CAAA) to issue rules to implement the law. In 1996 Federal EPA issued final rules governing nitrogen oxides (NOx) emissions that must be met after January 1, 2000 (Phase II of CAAA). The final rules will require substantial reductions in NOx emissions from certain types of boilers including those in the AEP System's power plants and the Company's power plant. To comply with Phase II of CAAA, the Company installed NOx emission control equipment at a capital cost of $14 million.

On September 24, 1998, Federal EPA finalized rules which require reductions in NOx emissions in 22 eastern states, including Kentucky where the Company's generating plant is located. The implementation of the final rules would be achieved through the revision of state implementation plans (SIPs) by September 1999. SIPs are a procedural method used by each state to comply with Federal EPA rules. The final rules anticipate the imposition of a NOx reduction on utility sources of approximately 85% below 1990 emission levels by the year 2003. On October 30, 1998, a number of utilities, including the Company and the other operating companies of the AEP System, filed petitions in the US Court of Appeals for the District of Columbia Circuit seeking a review of the final rules.

Should the states fail to adopt the required revisions to their SIPs within one year of the date of the final rules (September 24, 1999), Federal EPA has proposed to implement a federal plan to accomplish the NOx reductions. Federal EPA also proposed the approval of portions of petitions filed by eight northeastern states that would result in imposition of NOx emission reductions on utility and industrial sources in upwind midwestern states. These reductions are substantially the same as those required by the final NOx rules and could be adopted by Federal EPA in the event the states fail to implement SIPs in accordance with the final rules.

Preliminary estimates indicate that compliance could result in required capital expenditures of approximately $105 million. Compliance costs cannot be estimated with certainty and the actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers, they would have a material adverse effect on results of operations, cash flows and possibly financial condition.

Litigation

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns for the years 1991 to 1993 requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed by the Company in US District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1992-96. A disallowance of the COLI interest deductions through December 31, 1998 would reduce earnings by approximately $8 million (including interest). The Company has made no provision for any possible adverse earnings impact from this matter.

In 1998 the Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1992-97 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. These payments to the IRS are included on the balance sheet in other investments pending the resolution of this matter. The Company will seek refund, either administratively or through litigation, of all amounts paid plus interest. In order to resolve this issue without further delay, on March 24, 1998, the Company filed suit against the US in the US District Court for the Southern District of Ohio. Management believes that it has a meritorious position and will vigorously pursue this lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations and cash flows.

The Company is involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of litigation, it is not expected that the resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

3. RELATED-PARTY TRANSACTIONS:

KPCo has a Unit Power Purchase Agreement with AEP Generating Company (AEGCo) an affiliated company, which expires in 2004. The agreement provides for the Company to purchase 15% of the total output of the two unit 2,600-mw capacity Rockport Generating Plant. Under the Unit Power Purchase Agreement there is a demand charge for the right to receive the power, which is payable even if the power is not taken. The amount of the demand charge is such that when added to other amounts received by AEGCo, it will enable AEGCo to recover all its fixed expenses including a FERC-approved rate of return on common equity.

Demand charges payable even if the power is not taken and energy purchases under the Unit Power Purchase Agreement were included in purchased power expense as follows:

	Year Ended December 31, 1998	1997
	(in thousands)	
Demand Charge	$38,108	$39,993
Energy Charge	29,183	28,393
Total	$67,291	$68,386

Benefits and costs of the AEP System's generating plants are shared by the company and the other affiliated members of the AEP Power Pool. Under the terms of the System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the System's generating reserves among the AEP Power Pool members based on their relative peak demands and generating reserves. 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.

Operating revenues include $43.6 million in 1998 and $41.0 million in 1997 for energy supplied to the Power Pool.

Since the Company's internal peak demand exceeds its generating capacity, charges for capacity reservation, which is a charge for the right to receive power from the power pool even if the power is not taken, and charges for energy received from the Power Pool were included in purchased power expense as follows:

	Year Ended December 31, 1998	1997
	(in thousands)	
Capacity Charge	$1,169	$ 7,196
Energy Charge	8,504	13,855
Total	$9,673	$21,051

Power marketing and trading operations, which are described in Note 1, are conducted by the AEP Power Pool and shared with the Company. The Company's operating revenues, purchased power expense and nonoperating income includes amounts for power marketing and trading allocated by the AEP Power Pool as follows:

	Year Ended December 31, 1998	1997
	(in thousands)	
Operating Revenues	$29,237	$45,873
Purchased Power Expense	23,656	24,504
Nonoperating Loss	(2,419)	(22)

NOTES TO FINANCIAL STATEMENTS (continued)

AEP System electric operating utility companies participate in the AEP Transmission Equalization Agreement. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership of those facilities in proportion to the System companies' respective peak demands. Pursuant to the terms of the agreement since the Company's relative investment in transmission facilities is greater than its relative peak demand, other operation expense includes equalization credits of $6.0 million in 1998 and $2.7 million in 1997.

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies including the Company. The costs of the services are billed by AEPSC to its affiliated clients on a direct-charge basis whenever possible, and on reasonable bases of proration for shared services. 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 Co., Inc. Billings from AEPSC are expensed or capitalized depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

4. SEGMENT INFORMATION:

Effective December 31, 1998 the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information". The Company has one reportable seg..., a regulated vertically integrated electricity generation and energy delivery business. The Company's operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on business processes, cost structures and operating results. Included in the regulated electric utility segment is the power marketing and trading activities that are discussed in Note 1. For the years ended December 31, 1998 and 1997, all of the Company's revenues are derived from the generation, sale and delivery of electricity in the US.

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5. FINANCIAL INSTRUMENTS, CREDIT AND RISK MANAGEMENT:

The Company is subject to market risk as a result of changes in electricity commodity prices and interest rates. The Company participates in a power marketing and trading operation that manages the exposure to electricity commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices. For 1998, physical forward electricity contracts within the AEP System's traditional marketing area are recorded on a net basis as operating revenues in the month when the physical contract settles. The Company's share of the net gains from these regulated transactions for the year ended December 31, 1998 was $7 million.

Physical forward electricity contracts outside AEP's traditional marketing area and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional marketing area are marked to market and recorded in nonoperating income. The Company's share of the net losses from these non-regulated trading transactions for the year ended December 31, 1998 was $2 million. The unrealized mark-to-market gains and losses from such trading of financial instruments are reported as assets and liabilities, respectively. These activities were not material in prior periods.

The Company is exposed to risk from changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has fixed interest rates with terms from one day to twenty six years and an average duration of three years at December 31, 1998. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period. Also since the Company's rates are cost-based regulated, the risk of interest rate changes on debt used to finance regulated operations is mitigated.

Market Valuation

The book value of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments.

The book value amounts and fair values of the Company's significant financial instruments at December 31, 1998 and 1997 are summarized in the following table. 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 of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange. At December 31, 1997 the notional amounts and fair values of derivatives were not material.

	Book Value	Fair Value
	(in thousands)	
Non-Derivatives		
1998		
Long-term Debt	$368,838	$387,500
1997		
Long-term Debt	$341,051	$358,500

Derivatives

1998

	Fair Value	Average Fair Value
	(in thousands)	
Trading Assets		
Electric		
Physicals	$2,900	$2,600
Options	2,100	5,000
Swaps	200	100

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Trading Liabilities

Electric		
Futures	(400)	(100)
Physicals	(3,100)	(2,900)
Options	(1,900)	(5,600)
Swaps	(500)	(100)

At December 31, 1998 the notional amounts of the Company's nonregulated electric trading physical forward contract purchases and sales are 640 Gigawatt hours (Gwh) and 685 Gwh, respectively; the notional amounts for fixed priced swaps purchases and sales are 23 Gwh and 25 Gwh, respectively; and the notional amounts for options to purchase and to sell are 463 Gwh and 332 Gwh, respectively. The Company has a net long position of 25 Gwh for electric future contracts.

At December 31, 1998 the fair value of the assets and liabilities related to the wholesale electric forward contracts was $23 million and $23 million, respectively. The related notional amounts were 3,046 Gwh for purchases and 3,109 Gwh for sales. The average fair value amounts outstanding during the period were $59 million of assets and $56.0 million of liabilities.

Credit and Risk Management - In addition to market risk associated with electricity price movements, the Company through the AEP Power Pool is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of nonperformance. The AEP Power Pool has established and enforced credit policies that minimize this risk. The AEP Power Pool accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, the AEP Power Pool requires further credit enhancements to mitigate risk. Since the formation of the power marketing and trading business in July of 1997, the Company has experienced no significant losses due to the credit risk associated with risk management activities; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

6. STAFF REDUCTIONS:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing a better organizational structure for a competitive generation market. The study was completed in October 1998. In addition, a review of energy delivery staffing levels was conducted in 1998. As a result approximately 36 power generation and energy delivery positions were identified for elimination.

Severance accruals totaling $1.9 million were recorded by the Company in December 1998 for reductions in power generation and energy delivery staffs and were charged to other operation expense in the Statement of Income. In the first quarter of 1999 the power generation and energy delivery staff reductions were made.

7. BENEFIT PLANS:

The Company participates in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension costs for the years ended December 31, 1998 and 1997 were $322,000 and $424,000, respectively.

Postretirement Benefits Other Than Pensions are provided for retired employees for medical and death benefits under an AEP System plan. The annual accrued costs were $2.1 million in 1998 and $2.1 million in 1997.

A defined contribution employee savings plan required that the Company make contributions to the plan totaling $714,000 in 1998 and $714,000 in 1997.

8. FEDERAL INCOME TAXES:

The details of federal income taxes as reported are as follows:

	Year Ended December 31, 1998	1997
	(in thousands)	
Charged (Credited) to Operating Expenses (net):		
Current	$ 8,387	$10,425
Deferred	3,967	660
Deferred Investment Tax Credits	(1,202)	(1,219)
Total	11,152	9,866
Charged (Credited) to Nonoperating Income (net):		
Current	(794)	(359)
Deferred	(360)	81
Deferred Investment Tax Credits	(213)	(173)
Total	(1,367)	(451)
Total Federal Income Taxes as Reported	$ 9,785	$ 9,415

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The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate, and the amount of federal income taxes reported.

Year Ended December 31,

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	1998	1997
	(in thousands)	
Net Income	$21,676	$20,746
Federal Income Taxes	9,785	9,415
Pre-tax Book Income	$31,461	$30,161
Federal Income Taxes on Pre-tax Book Income at Statutory Rate (35%)	$11,011	$10,556
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:		
Depreciation	1,633	1,850
Removal Costs	(840)	(840)
Allowance For Funds Used During Construction	(373)	(364)
Percentage Repair Allowance	(460)	(456)
Corporate Owned Life Insurance	(134)	(328)
Investment Tax Credits (net)	(1,415)	(1,392)
Other	363	389
Total Federal Income Taxes as Reported	$ 9,785	$ 9,415
Effective Federal Income Tax Rate	31.1%	31.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences giving rise to it:

	December 31, 1998	December 31, 1997
	(in thousands)	
Deferred Tax Assets	$ 31,453	$ 34,276
Deferred Tax Liabilities	(190,159)	(188,221)
Net Deferred Tax Liabilities	$(158,706)	$(153,945)
Property Related Temporary Differences	$(112,246)	$(108,850)
Amounts Due From Customers For Future Federal Income Taxes	(18,759)	(18,320)
Deferred State Income Taxes	(31,460)	(31,561)
Other (net)	3,759	4,786
Net Deferred Tax Liabilities	$(158,706)	$(153,945)

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KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. 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.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of the deductibility of interest deductions related to AEP's corporate owned life insurance program, which is discussed under the heading, Litigation, in Note 2, 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.

9. COMMON SHAREHOLDER'S EQUITY:

The Company received from AEP Co., Inc. cash capital contributions of $20 million in 1998 and $20 million in 1997 which were credited to paid-in capital. There were no other transactions affecting common stock and paid-in capital accounts in 1998 and 1997.

10. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt by major category was outstanding as follows:

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	December 31, 1998	1997
	(in thousands)	
First Mortgage Bonds	$177,313	$179,410
Senior Unsecured Notes	77,553	47,708
Notes Payable	75,000	75,000
Junior Debentures	38,972	38,933
	368,838	341,051
Less Portion Due Within One Year	60,000	-
Total	$308,838	$341,051

First Mortgage Bonds outstanding were as follows:		December 31, 1998	1997
		(in thousands)	
% Rate	Due		
7.20	1999 - December 1	$ 35,000	$ 35,000
8.95	2001 - May 10	20,000	20,000
8.90	2001 - May 21	40,000	40,000
6.65	2003 - May 1	15,000	15,000
6.70	2003 - June 1	15,000	15,000
6.70	2003 - June 1	15,000	15,000
7.90	2023 - June 1	12,797	15,000
7.90	2023 - June 1	25,000	25,000

Unamortized Discount	(484)	(590)
Total	$177,313	$179,410

Certain first mortgage bond indentures contain maintenance and replacement provisions requiring the deposit of cash or bonds with a trustee or, in lieu thereof, certification of unfunded property additions.

Senior Unsecured Notes are composed of the following:

		December 31, 1998 (in thousands)	December 31, 1997 (in thousands)
% Rate	Due		
6.91	2007 - October 1	$48,000	$48,000
6.45	2008 - November 10	30,000	-
Unamortized Discount		(447)	(292)
Total		$77,553	$47,708

Notes Payable to Banks are composed of the following:

		December 31, 1998 (in thousands)	December 31, 1997 (in thousands)
% Rate	Due		
6.42	1999 - April 1	$25,000	$25,000
6.57	2000 - April 1	25,000	25,000
7.445	2002 - September 20	25,000	25,000
Total		$75,000	$75,000

Junior debentures are composed of the following:

		December 31, 1998 (in thousands)	December 31, 1997 (in thousands)
% Rate	Due		
8.72	2025 - June 30	$40,000	$40,000
Unamortized Discount		(1,028)	(1,067)
Total		$38,972	$38,933

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 1998, annual long-term debt payments are as follows:

	Amount (in thousands)
1999	$ 60,000
2000	25,000
2001	60,000

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2002	25,000
2003	45,000
Later Years	155,797
Total Principal Amount	370,797
Unamortized Discount	(1,959)
Total	$368,838

Short-term debt borrowings are limited by provisions of the 1935 Act to $150 million. Lines of credit are shared with AEP System companies and at December 31, 1998 and 1997 were available in the amounts of $763 million and $442 million, respectively. Facility fees of approximately 1/10 of 1% of the short-term lines of credit are required to maintain the lines of credit. Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1998:		
Notes Payable	$ 4,850	6.4%
Commercial Paper	15,500	6.0%
Total	$20,350	6.1%
December 31, 1997:		
Commercial Paper	$36,500	6.8%

11. LEASES:

Leases of property, plant and equipment are for periods of up to 30 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. The components of rental costs are as follows:

	Year Ended Decem-ber 31, 1998	1997
	(in thousands)	
Lease Payments on Operating Leases	$ 931	$ 369
Amortization of Capital Leases	4,265	3,541
Interest on Capital Leases	1,173	1,548
Total Lease Rental Costs	$6,369	$5,458

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Properties under capital leases and related obligations recorded on the Balance Sheet are as follows:

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	December 31, 1998	December 31, 1997
	(in thousands)	
Electric Utility Plant Under Capital Leases:		
Production Plant	$ 2,022	$ 2,000
General Plant	26,741	24,814
Total Electric Utility Plant	28,763	26,814
Accumulated Amortization	9,786	8,089
Net Electric Utility Plant Under Capital Leases	$18,977	$18,725
Capital Lease Obligations:*		
Noncurrent Liability	$14,957	$15,006
Liability Due Within One Year	4,020	3,719
Total Capital Lease Obligations	$18,977	$18,725

*Represents the present value of future minimum lease payments.

Properties under operating leases and related obligations are not included in the Balance Sheet.

Future minimum lease payments consisted of the following at December 31, 1998:

	Capital Leases	Non-cancelable Operating Leases
	(in thousands)	
1999	$ 5,147	$212
2000	4,355	149
2001	3,607	85
2002	3,096	26
2003	2,126	23
Later Years	4,634	275
Total Future Minimum Lease Payments	22,965	$770
Less Estimated Interest Element	3,988	
Estimated Present Value of Future Minimum Lease Payments	$18,977	

12. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1998 (in thousands)
Cash was paid for:	
Interest (net of capitalized amounts)	$27,857
Income Taxes	8,607
Noncash Acquisitions under Capital Leases	4,890

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

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	977,856,490	977,856,490
4	Property Under Capital Leases	18,911,912	18,911,912
5	Plant Purchased or Sold	218,671	218,671
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	996,987,073	996,987,073
9	Leased to Others		
10	Held for Future Use	6,862,819	6,862,819
11	Construction Work in Progress	30,075,995	30,075,995
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,033,925,887	1,033,925,887
14	Accum Prov for Depr, Amort, & Depl	305,760,505	305,760,505
15	Net Utility Plant (13 less 14)	728,165,382	728,165,382
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	305,555,668	305,555,668
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	204,838	204,838
22	Total In Service (18 thru 21)	305,760,506	305,760,506
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)	305,760,506	305,760,506

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. 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) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account 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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	44,589	1,876
4	(303) Miscellaneous Intangible Plant		592,649
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	44,589	594,525
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,545	
9	(311) Structures and Improvements	26,682,170	2,448,051
10	(312) Boiler Plant Equipment	135,830,877	10,554,688
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	64,427,234	-428,682
13	(315) Accessory Electric Equipment	13,447,286	363,986
14	(316) Misc. Power Plant Equipment	5,720,051	6,545
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	247,184,163	12,944,588
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements		
19	(322) Reactor Plant Equipment		
20	(323) Turbogenerator Units		
21	(324) Accessory Electric Equipment		
22	(325) Misc. Power Plant Equipment		
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)		
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights		
26	(331) Structures and Improvements		
27	(332) Reservoirs, Dams, and Waterways		
28	(333) Water Wheels, Turbines, and Generators		
29	(334) Accessory Electric Equipment		
30	(335) Misc. Power PLant Equipment		
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)		
33	D. Other Production Plant		
34	(340) Land and Land Rights		
35	(341) Structures and Improvements		
36	(342) Fuel Holders, Products, and Accessories		
37	Prime Movers		
38	Generators		
39	(345) Accessory Electric Equipment		

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

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.

6. 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.

7. 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.

8. 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
					2
			46,465		3
			592,649		4
			639,114		5
[redacted]					6
					7
			1,076,545		8
54,548			29,075,673		9
901,600		15,123	145,499,088		10
					11
695,946			63,302,606		12
24,960		-15,123	13,771,189		13
51,000			5,675,596		14
1,728,054			258,400,697		15
[redacted]					16
					17
					18
					19
					20
					21
					22
					23
[redacted]					24
					25
					26
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[redacted]					33
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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)
40	(346) Misc. Power Plant Equipment		
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)		
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	247,184,163	12,944,588
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	22,455,825	1,251,771
45	(352) Structures and Improvements	5,177,490	59,311
46	(353) Station Equipment	94,867,316	9,620,700
47	(354) Towers and Fixtures	78,198,423	967,169
48	(355) Poles and Fixtures	22,972,399	6,608,614
49	(356) Overhead Conductors and Devices	79,666,686	5,365,251
50	(357) Underground Conduit	11,590	
51	(358) Underground Conductors and Devices	106,066	
52	(359) Roads and Trails		
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	303,455,795	23,872,816
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	3,969,341	369,114
56	(361) Structures and Improvements	3,337,782	-68,252
57	(362) Station Equipment	41,136,166	-5,139,133
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	99,427,512	2,259,261
60	(365) Overhead Conductors and Devices	74,303,971	2,314,364
61	(366) Underground Conduit	2,071,740	60,158
62	(367) Underground Conductors and Devices	3,403,588	147,054
63	(368) Line Transformers	71,245,612	3,482,894
64	(369) Services	20,090,470	795,815
65	(370) Meters	21,055,678	1,324,431
66	(371) Installations on Customer Premises	8,471,424	600,987
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems	2,279,847	41,175
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	350,793,131	6,187,868
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	2,393,589	118,995
72	(390) Structures and Improvements	30,582,679	203,867
73	(391) Office Furniture and Equipment	918,926	-28,000
74	(392) Transportation Equipment	251,106	
75	(393) Stores Equipment	159,597	
76	(394) Tools, Shop and Garage Equipment	798,050	91,919
77	(395) Laboratory Equipment	414,191	
78	(396) Power Operated Equipment		
79	(397) Communication Equipment	3,798,156	1,765,990
80	(398) Miscellaneous Equipment	206,140	
81	SUBTOTAL (Enter Total of lines 71 thru 80)	39,522,434	2,152,771
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	39,522,434	2,152,771
84	TOTAL (Accounts 101 and 106)	941,000,112	45,752,568
85	(102) Electric Plant Purchased (See Instr. 8)	218,671	
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	941,218,783	45,752,568

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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.
					40
					41
1,728,054			258,400,697		42
					43
		2,435	23,710,031		44
6,190		2,147	5,232,758		45
165,269		39,014	104,361,761		46
			79,165,592		47
126,426			29,454,587		48
170,083			84,861,854		49
			11,590		50
			106,066		51
					52
467,968		43,596	326,904,239		53
					54
		7,188	4,345,643		55
22,733		-5,730	3,241,067		56
248,892		-22,960	35,725,181		57
					58
1,082,705			100,604,068		59
867,054			75,751,281		60
1,777			2,130,121		61
16,729			3,533,913		62
1,560,837		-14,139	73,153,530		63
431,172			20,455,113		64
723,727		-7,955	21,648,427		65
553,968			8,518,443		66
					67
20,374			2,300,648		68
5,529,968		-43,596	351,407,435		69
					70
		-680	2,511,904		71
3,693		-30,788	30,752,065		72
81,954			808,972		73
11,241			239,865		74
1,690			157,907		75
25,510			864,459		76
29,020			385,171		77
					78
982,587		31,468	4,613,027		79
34,504			171,636		80
1,170,199			40,505,006		81
					82
1,170,199			40,505,006		83
8,896,189			977,856,491		84
			218,671		85
					86
					87
8,896,189			978,075,162		88

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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 ITEM			
3	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	*NOTE (COLUMN C, LINE 6)			
11	NOT UNTIL 2000			
12				
13				
14				
15				
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21	Other Property:			
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47	Total			6,862,819

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in column (a) to kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items. 2. On Page 218 furnish information concerning construction overheads. 3. A respondent should not report "none" to the page if no overhead apportionments are made, but rather should explain on Page 218 the accounting procedures, employed and the amounts of engineering, supervision and administrative costs, etc. which are directly charged to construction. 4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of overhead (a)	Total amount charged for the year (b)
1	1. Kinds of Overhead	
2		
3	(A) Fossil / Hydro Generation Construction	795,860
4		
5	(B) Transmission and Station Construction	4,241,369
6		
7	(C) Energy Distribution Construction	5,537,430
8		
9	(D) Plant Capital Overheads	330,731
10		
11		
12		
13		
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46	TOTAL	10,905,390

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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	Distribution Blanket	3,886,066
2	Public Project Blanket	243,609
3	Distribution Customer Service Blanket	5,052,367
4	Transmission Blanket	1,907,318
5	General Plant Blanket	607,495
6	Big Sandy Flyash Retention Dam Extension	1,984,439
7	Big Sandy-Inez Project - Inez-Johns Creek 138KV Line	7,810,957
8	Big Sandy-Inez Project - R/W for Inez-Johns Creek 138KV Line	904,687
9	Big Sandy-Inez Project - Inez 138KV Station	275,396
10	Prestonburg Area Improvements	1,370,282
11	Production Blanket	184,110
12	Transmission Public Projects Relocation Blanket	102,488
13	Olivehill-Hayward 12KV Distribution Line Improvements	683,017
14	Beaver Creek-Johns Creek 138KV Line	777,485
15	John's Creek-Sprigg 138KV Line	1,850,472
16	Supervisory Control Installation	109,561
17	Capitalize Computer Software Costs	1,233,620
18	Minor Projects Less Than $100,000	1,092,626
19		
20		
21		
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43	TOTAL	30,075,995

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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant instructions 3(17) of the U.S. of A.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

*SEE FOOTNOTE

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio(Percent) (c)	Cost Rate Percentage (d)
1	Average Short-Term Debt & Computation of Allowance text	S 38,942,000		
2	Short-term Interest			s 6.48
3	Long-Term Debt	D 339,667,000	56.90	d 7.99
4	Preferred Stock	P		p
5	Common Equity	C 257,276,000	43.10	c 9.20
6	Total Capitalization	596,943,000	100%	
7	Average Construction Work in Progress Balance	W 27,226,000		

2. Gross Rate for Borrowed Funds $s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$ 6.48

3. Rate for Other Funds $\left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$ 0.00

4. Weighted Average Rate Actually Used for the Year:
   a. Rate for Borrowed Funds - 6.50
   b. Rate for Other Funds - 0.00

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
218	1	OH exp

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

A. Fossil/Hydro Generation Construction Overheads applicable to steam plant construction.

(a) Charges represent salaries and expenses of the Company's engineering and supervision applicable to steam plant construction. Also included are engineering services performed by the Engineering Department of American Electric Power Service Corporation (AEPSC) applicable to steam plant construction.

(b) Company charges are capitalized based on work studies and daily time records. In accordance with provisions of a service agreement between AEPSC and the respondent, approved by the Securities & Exchange Commission February 19, 1981, salaries, expenses and overheads of AEPSC personnel directly relating to construction activities are collected by means of a work order system and billed to the respondent as:

(1) Identifiable costs, generally relating to major construction projects, for which time keeping and other specific cost identification are economically feasible, and

(2) Non-identifiable costs, generally relating to numerous small construction projects, for which time keeping and other specific cost identification are not economically feasible.

(c) Company charges are spread to all applicable construction projects in proportion to the direct costs charged to such projects. Charges billed by AEPSC as (b) (1) above are charged direct by respondent to the applicable specific construction projects. Charges billed by AEPSC as (b) (2) above are allocated to all applicable construction projects in proportion to the direct costs charged to such projects.

(d) A uniform rate is applied to all subject construction expenditures.

(e) Not Applicable. See (d) above.

(f) See (c) above.

B. Transmission and Station Construction Overheads applicable to all transmission plant and to distribution station construction.

(a) Charges represent salaries and expenses of the Company's administrative and general, engineering, supervision and

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
204	85	g

The South Portsmouth Metering Station located in Greenup County, Kentucky, was purchased from the City of Hamilton, Ohio, in November 1997 and constituted the purchase of an operating unit or system. Proposed journal entries were filed with the Commission on December 12, 1997, but no response has been received from the Commission.

Description	Additions
Original Cost of Facilities	232,779
Accumulated Provision for Depreciation	(14,108)
Total Line 85, Column (C)	218,671

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)	

related drafting and technical work applicable to all transmission plant and to distribution station construction. Also included are engineering services performed by the Engineering Department of American Electric Power Service Corporation (AEPSC) applicable to all transmission plant and to distribution station construction.

(b) Company charges are capitalized based on work studies and daily time records. In accordance with provisions of a service agreement between AEPSC and the respondent, approved by the Securities & Exchange Commission February 19, 1981, salaries, expenses and overheads of AEPSC personnel directly relating to construction activities are collected by means of a work order system and billed to the respondent as:

(1) Identifiable costs, generally relating to major construction projects, for which time keeping and other specific cost identification are economically feasible, and

(2) Non-identifiable costs, generally relating to numerous small construction projects, for which time keeping and other specific cost identification are not economically feasible.

(c) Company charges are spread to all applicable construction projects in proportion to the direct costs charged to such projects. Charges billed by AEPSC as (b) (1) above are charged direct by respondent to the applicable specific construction projects. Charges billed by AEPSC as (b) (2) above are allocated to all applicable construction projects in proportion to the direct costs charged to such projects.

(d) A uniform rate is applied to all subject construction expenditures.

(e) Not Applicable. See (d) above.

(f) See (c) above.

C. Energy Distribution Construction Overheads applicable to all distribution plant construction except for distribution station construction.

(a) Charges represent salaries and expenses of the Company's administrative and general, engineering, supervision and related drafting and technical work applicable to all distribution plant construction except for distribution station construction. Also included are engineering services performed by the Engineering Department of American Electric Power Service Corporation (AEPSC) applicable to all distribution plant construction

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except for distribution station construction.

(b) Company charges are capitalized based on work studies and daily time records. In accordance with provisions of a service agreement between AEPSC and the respondent, approved by the Securities & Exchange Commission February 19, 1981, salaries, expenses and overheads of AEPSC personnel directly relating to construction activities are collected by means of a work order system and billed to the respondent as:

(1) Identifiable costs, generally relating to major construction projects, for which time keeping and other specific cost identification are economically feasible, and

(2) Non-identifiable costs, generally relating to numerous small construction projects, for which time keeping and other specific cost identification are not economically feasible.

(c) Company charges are spread to all applicable construction projects in proportion to the direct costs charged to such projects. Charges billed by AEPSC as (b) (1) above are charged direct by respondent to the applicable specific construction projects. Charges billed by AEPSC as (b) (2) above are allocated to all applicable construction projects in proportion to the direct costs charged to such projects.

(d) A uniform rate is applied to all subject construction expenditures.

(e) Not Applicable. See (d) above.

(f) See (c) above.

D. Plant Capital Overheads applicable to steam plant construction.

(a) Charges representing AEPSC Regional Service Organization salaries and expenses applicable to steam plant construction.

(b) AEPSC Regional Service Organization charges a generating station specific plant capital overhead work order for minor capital projects.

(c) Costs are spread to all applicable construction projects in proportion to the direct costs charged to such projects.

(d) A uniform rate is applied to all subject construction

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)	

projects.

(e) Not Applicable. See (d) above.

(f) See note (c) above.

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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	288,028,379	288,028,379		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	28,038,044	28,038,044		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	28,038,044	28,038,044		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	8,862,242	8,862,242		
12	Cost of Removal	3,115,499	3,115,499		
13	Salvage (Credit)	1,466,720	1,466,720		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	10,511,021	10,511,021		
15	Other Debit or Cr. Items (Describe):	266	266		
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	305,555,668	305,555,668		
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production	133,112,141	133,112,141		
19	Nuclear Production				
20	Hydraulic Production-Conventional				
21	Hydraulic Production-Pumped Storage				
22	Other Production	81,478,319	81,478,319		
23	Transmission	79,880,277	79,880,277		
24	Distribution	11,084,931	11,084,931		
25	General				
26	TOTAL (Enter Total of lines 18 thru 25)	305,555,668	305,555,668		

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of Nonutility property included in Account 121.
2. Designate with a double asterisk any property which is Leased to another company. State name of Lessee and whether Lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is Less) may be-grouped by (1) previously devoted to public service (Line 44), or (2) other Nonutility property (Line 45).

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	Property Previously Devoted To Public Service:			
2	Old Betsy Lane Station Site, Including Improvements			
3	Floyd County, Kentucky, Transferred 1941	12,616		12,616
4				
5	Old Pikeville Service Building, Pike County			
6	Transferred 1982	109,391		109,391
7				
8	Land Old Pikeville Service Building, Pike County			
9	Transferred 1982	25,773		25,773
10				
11	Land Old Ashland Service Building			
12	Transferred 1990-Portion Sold 1994	42,820		42,820
13				
14				
15	Other Non-Utility Property:			
16	Mud Creek Microwave Site, Floyd County, Kentucky			
17	Transferred 1975	2,051		2,051
18				
19	R/W for Savage Branch-South Neal 138kV Line,			
20	Boyd County, Kentucky, Transferred 1971	2,225		2,225
21				
22	R/W for 345kV Corridor in Trimble County,			
23	Kentucky, Transferred 1983	330,782		330,782
24				
25	Land Purchased for R/W for 345 kV Corridor in			
26	Trimble County, Kentucky, Transferred 1982	416,807		416,807
27				
28	Ashland Service Center Land - Leased to			
29	Pikeville Construction - Non Assoc.	31,179		31,179
30				
31	Water Heater Leasing Program-Switch (L)		65,413	65,413
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44	Minor Item Previously Devoted to Public Service			
45	Minor Items-Other Nonutility Property			
46	TOTAL	973,644	65,413	1,039,057

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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)	10,379,192	7,635,967	
2	Fuel Stock Expenses Undistributed (Account 152)	306,130	251,860	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	799,421	638,585	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	5,400,844	5,195,122	
8	Transmission Plant (Estimated)	589,690	154,156	
9	Distribution Plant (Estimated)	962,127	327,582	
10	Assigned to - Other			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	7,752,082	6,315,445	
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)	149,395		
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	18,586,799	14,203,272	

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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)	1999 No. (d)	1999 Amt. (e)
1	Balance-Beginning of Year	50,769.00	4,781,573		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	COMED	3,176.00	349,995		
10	Enron	2,232.00	381,802		
11	EPA Auction	2,566.00	295,091		
12	Sempra	1,605.00	173,981		
13	SoCal Edison				
14	All Others	12,168.00	1,770,376		
15	Total	21,747.00	2,971,245		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	Ohio Power	5,385.00	584,638		
24	APS Co.	7,024.00	711,053		
25	ENRON	2,702.00	284,887		
26	Sigeco	1,605.00	155,700		
27	All Others	7,583.00	781,709		
28	Total	24,299.00	2,517,987		
29	Balance-End of Year	48,217.00	5,234,831		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		782,809		
33	Net Sales Proceeds (Other)		3,061,722		
34	Gains		-1,285,586		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

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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.

2000		2001		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
27,229.00	193,650	32,071.00	918,335	658,371.00	258,701	768,440.00	6,152,259	1
								2
								3
201.00		201.00		28,253.00		28,655.00		4
								5
								6
								7
								8
191.00	31,591	191.00	31,591	955.00	157,957	4,513.00	571,134	9
						2,232.00	381,802	10
						2,566.00	295,091	11
693.00	127,945	317.00	58,423	1,046.00	192,644	3,661.00	552,993	12
257.00	31,854	257.00	31,854	449.00	67,548	963.00	131,256	13
						12,168.00	1,770,376	14
1,141.00	191,390	765.00	121,868	2,450.00	418,149	26,103.00	3,702,652	15
								16
								17
								18
								19
								20
								21
								22
						5,385.00	584,638	23
						7,024.00	711,053	24
						2,702.00	284,887	25
						1,605.00	155,700	26
						7,583.00	781,709	27
						24,299.00	2,517,987	28
28,571.00	385,040	33,037.00	1,040,203	689,074.00	676,850	798,899.00	7,336,924	29
								30
								31
							782,809	32
							3,061,722	33
							-1,285,586	34
								35
361.00		361.00		17,731.00		18,453.00		36
				720.00		720.00		37
								38
				362.00		362.00		39
361.00		361.00		18,089.00		18,811.00		40
								41
								42
								43
					40,145		40,145	44
					40,145		40,145	45
								46

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
228	14	b

Detail for ALL OTHERS line 14, Columns b & c

	#	$
Aquila	635	108,351
AES	4	408
APS Co.	4,540	649,472
Cantor Fitzgerald	530	87,708
Courtney Foos Coal	46	7,147
LG&E	321	45,068
Natsource	24	3,888
Ohio Edison	321	41,055
Ohio Power	569	0
Peabody Coal	318	47,668
PG&E	2,171	266,007
PSCNH	1,824	381,945
PSE&G	223	36,233
Vitol	321	47,636
Wisconsin Pub Serv	321	47,790

228	14	c

Footnote Linked. See note on 228, Row: 14, col/item: b

228	27	b

Detail for ALL OTHERS Line 27, Columns b & c

	#	$
Aquila	954	103,543
Cantor Fitzgerald	1,441	146,533
Cinergy	636	66,222
DP&L	642	61,137
LG&E	321	31,140
Orange & Rockland	15	1,486
Phibro, Inc.	642	62,280
Potomac Electric	165	17,913
PP&L	798	80,235
PSE&G	318	32,179
Rochester G & E	63	6,559
Southern Company	635	68,674
SCEM	159	17,262
Texas Utilities	159	17,195
Vitol	635	69,351

228	27	c

Footnote Linked. See note on 228, Row: 27, col/item: b

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	SFAS 109 Deferred Federal Income Tax		VAR	1,532,324	68,415,211
2	Depreciation Expenses - Hanging Rock/Jefferson				
3	765 kV Line		VAR	5,208	176,641
4	Post In-Service AFUDC- Hanging Rock/Jefferson				
5	765 kV Line		406.2	33,408	1,133,352
6	Post Employment Benefits	364,430	228.33		4,206,240
7	SFAS 109 Deferred State Income Tax		283.09	101,000	31,460,000
8	Carrying Charges - Purchased Allowances		VAR	2,529	277,620
9	Excess of Base Fuel Cost Deferred	877,555	254.12	266,698	610,857
10	Deferred DSM Expense	36,971,803	VAR	36,521,553	363,493
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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33					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	38,213,788		38,462,720	106,643,414

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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 Deffered Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Accrual Adjustment					
2	Ky Real Estate Personal &					
3	Franchise Tax	5,120,000	5,380,000	408.30	5,120,000	5,380,000
4						
5	Switch Hot Water Tanks	23,409	58,247	131.00	71,305	10,351
6						
7	MDD - Allowances	409	3,221,756	VAR	3,441,647	-219,482
8						
9	MDD - Deferred Emission Commiss	100,695		401.90	100,695	
10						
11	Unmatched Procurement Card					
12	Transactions	19,380	63,547	VAR	78,766	4,161
13						
14	Miscellaneous Deferred Expenses		51,306			51,306
15						
16	Minor Items	-2,192	26,583	VAR	24,219	172
17						
18	Misc Work In Progress	311,619	33,352,842	VAR	32,875,160	789,301
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	5,573,320				6,015,809

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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	2,287,910	2,477,523
3	Contribution-In-Aid-of-Construction	1,676,803	1,777,690
4	Accrued Book Pension Expense	1,414,239	1,481,947
5	Deferred Fuel	1,267,853	180,800
6	INA Insurance Cost	968,252	879,024
7	Other	2,883,602	2,744,868
8	TOTAL Electric (Enter Total of lines 2 thru 7)	10,498,659	9,541,852
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	23,777,571	21,911,308
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	34,276,230	31,453,160

Notes

< Page 234 Line 7 Columns B & C >

	Beginning Of Year	End Of Year
Bk Amort Dumont Test Ctr - Norm	3,276	3,170
Provision For Workers' Comp Costs	246,277	0
Customer Advances	-4,928	-3,937
Accrued Book Sup. Savings Plan Exp.	442	442
Accrued PSI Plan Expense	64,050	0
Provision For Uncollectible Accounts	184,389	297,813
Deferred Compensation	41,564	37,413
Book Loss Prov. - Plant M&S	128,348	128,348
Accrued Companywide Incentive Plan	287,003	67,624
Accrued Vacation Pay	913,933	750,111
Management Incentive Bonus	18,899	<20,348>
Accrued Bk. Severance Benefits	0	494,722
Bk. Amort - Demand Side Management	30,364	<127,949>
Accrued Asbestos Lawsuit	30,654	30,654
Tax > Book Basis - EMA	35,111	45,680
Defd Bk Gain - Interco Sale - EMA	0	<17,044>
Advance Rental Income	6,577	336
Capitalized Software Costs - Tax	0	23,713
SFAS 106 - Post Retirement Benefit	487,010	686,767
IRS Audit Settlements	410,633	347,353
TOTAL - Line 7	2,883,602	2,744,868

< Page 234 Line 17 Column B & C >

Non-Utility Items - Account 190.2	88,604	448,629
SFAS 109 Regulatory Asset - Account 190.3 & 190.4	23,688,967	21,462,679
TOTAL - Line 17	23,777,571	21,911,308

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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				
8				
9				
10				
11				
12				
13				
14				
15				
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42	TOTAL_COM	2,000,000	50.00	

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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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1,009,000	50,450,000					42

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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		
3	Contributions by Parent Company	
4		
5	Prior to 1998	128,750,000
6		
7	Cash Contribution in 1998	10,000,000
8		
9	Cash Contribution in 1998	10,000,000
10		
11		
12	SUBTOTAL	148,750,000
13		
14	Account 209 - Reduction in Par or Stated Value of Capital Stock	
15		
16	Account 210 - Gain on Resale or Cancellation of Reacquired Capital Sto	
17		
18	Account 211 - Miscellaneous Paid-In Capital	
19		
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40	TOTAL	148,750,000

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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	First Mortgage Bonds 8.95% Series	20,000,000	78,933
2			125,000 D
3	First Mortgage Bonds 8.90% Series	40,000,000	157,870
4			250,000 D
5	First Mortgage Bonds 7.20% Series	35,000,000	263,125
6			210,000 D
7	First Mortgage Bonds 6.65% Series	15,000,000	78,937
8			93,750 D
9	First Mortgage Bonds 6.70% Series	15,000,000	48,113
10			93,750 D
11	First Mortgage Bonds 7.90% Series	15,000,000	48,113
12			112,500 D
13	First Mortgage Bonds 7.90% Series	25,000,000	80,188
14			187,500 D
15	First Mortgage Bonds 6.70% Series	15,000,000	48,113
16			93,750 D
17			
18	Junior Subordinated Deferrable Debentures	40,000,000	178,044
19			
20			1,175,188 D
21			
22	Subtotal - Account 221	220,000,000	3,322,874
23			
24	Account 224		
25	Term Loan Bank of NY 6.42%	25,000,000	
26	Term Loan Bank of NY 6.57%	25,000,000	
27	Term Loan Societe Generale 7.445%	25,000,000	
28	Medium Term Notes - 6.91% Series	48,000,000	113,066
29			300,000 D
30	Medium Term Notes - 6.45% Series		70,666
31	(KY PSC Order 97-454 and	30,000,000	187,500 D
32	Registration Statement No. 333-35767 dated 9-23-97)		
33	TOTAL	373,000,000	3,994,106

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
05/10/91	05/10/01	05/10/91	05/10/01	20,000,000	1,790,004	1
						2
05/20/91	05/21/01	05/20/91	05/21/01	40,000,000	3,560,004	3
						4
12/01/92	12/01/99	12/01/92	12/01/99	35,000,000	2,520,000	5
						6
04/23/93	05/01/03	04/23/93	05/01/03	15,000,000	997,500	7
						8
05/20/93	06/01/03	05/20/93	06/01/03	15,000,000	1,005,000	9
						10
05/20/93	06/01/23	05/20/93	06/01/23	12,797,000	1,083,479	11
						12
06/09/93	06/01/23	06/09/93	06/01/23	25,000,000	1,974,996	13
						14
06/24/93	07/01/03	06/24/93	07/01/03	15,000,000	1,005,000	15
						16
						17
04/20/95	06/30/25	04/20/95	06/30/25	40,000,000	3,488,004	18
						19
						20
						21
				217,797,000	17,423,987	22
						23
						24
	04/01/99			25,000,000	1,605,000	25
	04/01/00			25,000,000	1,642,500	26
	09/20/02			25,000,000	1,861,248	27
10/01/97	10/01/07	10/01/97	10/01/07	48,000,000	3,316,800	28
						29
						30
11/09/98	11/10/08	11/09/98	11/10/08	30,000,000	274,125	31
						32
				370,797,000	26,123,660	33

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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)	21,675,855
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	24,751,497
28	Show Computation of Tax:	
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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
261	27	b

KENTUCKY POWER COMPANY

Income For Year (Page 117)	$	21,675,855
Total Federal Income Taxes		9,784,860
Pre-Tax Book Income		31,460,715
Increase (Decrease) In Taxable Income Resulting From:		
Allowance For Funds Used During Construction & Miscellaneous Items Capitalized On The Books But Deducted For Tax Purposes		246,809
Excess Of Tax Over Book Depreciation		(2,361,110)
Removal Cost		(2,400,000)
Deferred Fuel		(448,760)
Charges To Clearing Accounts (Net)		77,709
Reserve For Self Insurance (Net)		(1,425,697)
Uncollectible Accounts (Net)		325,856
Deferred Compensation (Net)		(36,726)
Uncollectible Accounts (Net) - O. I. D.		(3,408)
Vacation Pay (Net)		(75,753)
Accrued Mgt. Incentive Bonus		(52,503)
Accrued Companywide Incentive Plan •		(626,797)
Accrued Severance Benefits		1,413,490
Provision For Trading Credit Risk		44,550
Pension Trust Expense		322,283
Demand Side Management		(452,320)
Advance Rental (Net)		(17,830)
Interest Payment To IRS		(936,685)
Excess Tax Versus Book Gain		1,347,535
Emission Allowances (Net)		(1,174,832)
Loss On Reacquired Debt (Net)		136,164
Non Deductible Meals, Lobbying, Travel, & Memberships (Net)		220,499
Corporate Owned Life Insurance		(383,375)
Post Retirement Benefits		1,005,056
Capitalized Software Costs		(1,333,952)
Amort IRS Settlements		(119,421)
Federal Tax Net Income - Estimated Current Year Taxable Income		24,751,497
Show Computation Of Tax:		
Federal Income Tax On Current Taxable Income (Separate Return Basis) At The Statutory Rate Of 35%		8,663,024
Adjustment Due To System Consolidation	(A)	(168,971)
Estimated Currently Payable	(B)	8,494,053
Adjustments of Prior Year Accruals (Net)		(901,155)
Estimated Current Federal Income Tax Expense		7,592,898

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

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)	

(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 current 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 utilized to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power 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.

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 1998 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed in September, 1999. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until October, 1999.

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Taxes on Income	-1,006,551		7,592,898	6,080,267	
3						
4	Unemployment Ins. - 1996	2,741				
5	Unemployment Ins. - 1997	117				
6	Unemployment Ins. - 1998			40,454	43,192	
7						
8	Ins. Contrib. Act 1996	31,387				
9	Ins. Contrib. Act - 1997	23,669				
10	Ins. Contrib. Act - 1998			2,711,074	2,724,534	
11						
12	Emp. Taxes - Accrued P/R	43,190		308,285	302,215	
13						
14	STATE OF KENTUCKY					
15	Taxes on Income	546,574		2,071,330	2,450,000	
16	PSC Maint. Rem. Asst. 1997		201,762	446,562	489,597	
17						
18	Unemp. Ins. - 1996	1,347				
19	Unemp. Ins. - 1997	-57				
20	Unemp. Ins. - 1998			21,934	23,159	
21						
22	Intang. Prop. Tax - 1997			-249	199,858	
23	Use Tax			357,390	26,415	
24						
25	Real & Pers. Prop 1993	61,356		-61,356		
26	Real & Pers. Prop 1996	141,623		-68,053	73,570	
27	Real & Pers. Prop 1997	1,159,737		68,053	1,187,440	
28	Real & Pers. Prop 1998	5,120,000		155,791	4,341,468	
29	Real & Pers. Prop 1999			5,380,000		
30						
31	Real & Pers.	4,203		-4,203		
32	Real & Pers.			32,103	26,103	
33						
34	STATE OF WEST VIRGINIA					
35	Taxes on Income			79,502	77,122	
36						
37	Business Franchise Tax -			5,521	5,521	
38	Business Franchise Tax -			7,000	10,000	
39	Unemployment Ins. - 1997	304			304	
40	Unemployment Ins. - 1998			9,517	9,516	
41	TOTAL	6,129,640	201,762	19,153,553	18,070,281	

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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 (l) 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
506,080		8,386,861			-793,963	2
						3
2,741						4
117						5
-2,738		24,570			15,884	6
						7
31,387						8
23,669						9
-13,460		1,729,875			981,199	10
						11
49,260					308,285	12
						13
						14
167,904		2,346,482			-275,152	15
	244,797	446,562				16
						17
1,347						18
-57						19
-1,225		14,527			7,407	20
						21
-200,108					-249	22
330,975					357,390	23
						24
		-61,356				25
		-68,053				26
40,350		68,053				27
934,323		155,791				28
5,380,000		4,964,209			415,791	29
						30
					-4,203	31
6,000					32,103	32
						33
						34
2,380		54,251			25,251	35
						36
		5,521				37
-3,000		7,000				38
						39
1					9,517	40
7,255,946	244,797	18,074,293			1,079,260	41

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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 Begining 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%	1,247,391			411.4	143,915	-21,155
4	7%						
5	10%	14,367,438	282	-218	411.4	1,058,233	-191,409
6							
7							
8	TOTAL	15,614,829		-218		1,202,148	-212,564
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
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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
1,082,321	30 Yrs.		3
			4
13,117,578	30 Yrs.		5
			6
			7
14,199,899			8
			9
			10
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			48

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
266	3	g

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Adjustment of Prior Years' Federal Income Tax Returns

Account 411.5 (21,155)

Page Number (a)	Item (row) Number (b)	Column Number (c)
266	5	g

Adjustment of Prior Years' Federal Income Tax Return

Account 411.5 (191,409)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 Deffered Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Wintercare - Customer Donations	6,828	131.00	1,153	4,911	10,586
2						
3	Lessee Rent Prepayments -					
4	FRECO Property	17,830	VAR	23,080	5,250	
5						
6	Option Sales	-1			1	
7						
8	Speculative Options	149,034	VAR	14,921,273	15,632,299	860,060
9						
10	Allowances		VAR	3,061,723	3,242,100	180,377
11						
12	AEP Communication Leases		108.50	266	55,386	55,120
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
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33						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	173,691		18,007,495	18,939,947	1,106,143

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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	78,824,530	7,076,659	4,252,808
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	78,824,530	7,076,659	4,252,808
6	Accum DFIT-Other Property	17,914		
7	SFAS 109	40,503,964		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	119,346,408	7,076,659	4,252,808
10	Classification of TOTAL			
11	Federal Income Tax	119,346,408	7,076,659	4,252,808
12	State Income Tax			
13	Local Income Tax			

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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.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
						81,648,381	2
							3
							4
						81,648,381	5
						17,914	6
		182/254	399,093			40,104,871	7
							8
			399,093			121,771,166	9
							10
			399,093			121,771,166	11
							12
							13

NOTES (Continued)

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information Called for below concerning the respondent's accounting for deferred income taxes rating 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	1,324,585	2,881,828	3,811,815
4	Interest Payment to IRS		327,840	
5	Capitalized Software - Book		466,882	
6	Loss on Reacquisition of Debt	258,433		41,217
7	Emission Allowances	170,970	398,158	8,438
8	Other	31,822	213,534	240,733
9	TOTAL Electric (Total of lines 3 thru 8)	1,785,810	4,288,242	4,102,203
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	SFAS 109	67,089,094		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	68,874,904	4,288,242	4,102,203
20	Classification of TOTAL			
21	Federal Income Tax	37,313,904	4,288,242	4,102,203
22	State Income Tax	31,561,000		
23	Local Income Tax			

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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.
[redacted]							1
[redacted]							2
						394,598	3
						327,840	4
						466,882	5
						217,216	6
						560,690	7
46,938	46,936					4,625	8
46,938	46,936					1,971,851	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
		182/254	672,651			66,416,443	18
46,938	46,936		672,651			68,388,294	19
[redacted]							20
46,938	46,936		571,651			36,928,294	21
			101,000			31,460,000	22
							23

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OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (Details) called for concerning other regulatory liabilities which are created through the rate-making actions of regulatory agencies (and not includable in other amounts)
2. For regulatory Liabilities being amortized show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is Less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities	DEBITS		Credits	Balance at End of Year
		Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)
1	SFAS 109 Deferred Federal Income Tax	190.3	1,889,385		7,646,204
2	Excess of Base Fuel Cost Deferred	401.9	23,724,960	23,589,225	
3	Excess of Base Fuel Cost Deferred-				
4	Accrued Utility Revenue	401.9	311,470	609,302	
5					
6	SFAS 109 Excess Deferred Federal Income Taxes	VAR	898,265		7,170,590
7					
8	Deferred Emission Allowance Gains	VAR	502,452	449,339	-10,278
9					
10					
11					
12					
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40					
41	TOTAL		27,326,532	24,647,866	14,806,516

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ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. 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.
3. If increases or decreases from previous year (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 Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	104,706,566	105,917,091
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	60,114,660	58,679,922
5	Large (or Ind.) (See Instr. 4)	94,186,047	94,644,445
6	(444) Public Street and Highway Lighting	876,894	863,808
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	259,884,167	260,105,266
11	(447) Sales for Resale	87,400,963	89,336,603
12	TOTAL Sales of Electricity	347,285,130	349,441,869
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	347,285,130	349,441,869
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,350,090	1,363,157
17	(451) Miscellaneous Service Revenues	221,659	413,800
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,807,255	1,315,284
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	11,334,490	7,009,239
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	15,713,494	10,101,480
27	TOTAL Electric Operating Revenues	362,998,624	359,543,349

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ELECTRIC OPERATING REVENUES (Account 400)

4. 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.)
5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increase or decreases.
6. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	No.
				1
2,156,126	2,196,748	142,783	142,198	2
				3
1,194,520	1,165,684	24,312	23,691	4
3,130,767	3,141,795	1,654	1,690	5
10,529	10,313	500	476	6
				7
				8
				9
6,491,942	6,514,540	169,249	168,055	10
4,883,277	5,893,932	113	66	11
11,375,219	12,408,472	169,362	168,121	12
				13
11,375,219	12,408,472	169,362	168,121	14

Line 12, column (b) includes $ 578,504 of unbilled revenues.
Line 12, column (d) includes -12,558 MWH relating to unbilled revenues

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Unmetered Sales Included in Service:

	440	442	444
Customers	21,186	3,660	17
Revenues	2,327,570	951,634	8,408
MWH Sales (Estimated)	21,953	10,668	60

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - RESIDENTIAL					
2	RS	2,125,376	101,664,110	142,404	14,925	0.0478
3	RS - LM - TOD	6,016	200,471	372	16,172	0.0333
4	RS - TOD	38	1,159	2	19,000	0.0305
5	OL	21,953	2,327,570			0.1060
6	SGS	20	1,007	5	4,000	0.0504
7	MGS		-403			
8	LGS		10,000			
9	UNBILLED REVENUE	2,723	502,652			0.1846
10						
11	SUBTOTAL RESIDENTIAL	2,156,126	104,706,566	142,783	15,101	0.0486
12						
13						
14						
15	442 - COMMERCIAL & INDUSTRIAL					
16	SGS	64,866	4,978,321	14,500	4,474	0.0767
17	MGS	547,675	30,812,742	10,451	52,404	0.0563
18	MGS - TOD	1,542	73,312	85	18,141	0.0475
19	LGS	819,963	35,404,552	812	1,009,807	0.0432
20	LGS - LM - TOD	2,325	86,376	6	387,500	0.0372
21	IRP	180,474	4,926,256	1	180,474,000	0.0273
22	QP	903,090	29,154,051	68	13,280,735	0.0323
23	CIP - TOD	1,798,855	47,375,207	12	149,904,583	0.0263
24	MW	11,147	464,825	28	398,107	0.0417
25	OL	10,668	951,634			0.0892
26	RS	9	434	3	3,000	0.0482
27	UNBILLED REVENUE	-15,327	72,997			-0.0048
28						
29	SUBTOTAL COMMERCIAL &	4,325,287	154,300,707	25,966	166,575	0.0357
30						
31						
32						
33	444 - PUBLIC STREET & HIGHWAY					
34	SGS	2,053	147,036	432	4,752	0.0716
35	MGS	691	37,878	17	40,647	0.0548
36	SL	7,679	680,718	51	150,569	0.0886
37	OL	60	8,408			0.1401
38	UNBILLED REVENUE	47	2,854			0.0607
39						
40	SUBTOTAL PUBLIC STREET &	10,530	876,894	500	21,060	0.0833
41	TOTAL Billed	6,504,501	259,305,663	169,249	38,432	0.0399
42	Total Unbilled Rev.(See Instr. 6)	-12,558	578,504	0	0	-0.0461
43	TOTAL	6,491,943	259,884,167	169,249	38,357	0.0400

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FOOTNOTE DATA

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304	1	a

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PER INSTRUCTION #5

Amount of fuel clause included in rate:

Residential	RS	(1,542,648)
Residential	RS - LM - TOD	(3,740)
Residential	RS - TOD	(28)
Small General Service	SGS	(50,113)
Medium General Service	MGS	(438,547)
Medium General Service	MGS - TOD	(1,094)
Large General Service	LGS	(659,643)
Large General Service	LGS - LM - TOD	(2,137)
Outdoor Lights	OL	(24,030)
Quantity Power	QP	(738,380)
Street Lighting	SL	(5,824)
Mun. Waterworks	MW	(9,655)
Interruptible Power	IRP	(157,019)
Commercial Industrial Power	CIP - TOD	(1,448,409)

		(5,081,267)
		===========

304	5	d

Average number of OL customers not included in total = 24,863

304	25	d

Footnote Linked. See note on 304, Row: 5, col/item: d

304	37	d

Footnote Linked. See note on 304, Row: 5, col/item: d

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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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Hamilton	RQ	OPCO 96	0	0	0
2	Olive Hill	RQ	KPCO 13	5.1	5.1	5.1
3	Vanceburg	RQ	KPCO 18	10	10	10
4						
5	North Carolina Electric Membership Corp	LF	APCO 135			
6	American Municipal Power, Oh	LF	OPCO 74			
7						
8	American Municipal Power, Oh	SF	OPCO 74			
9	Cleveland Public Power	SF	Note 1			
10						
11	Carolina Power & Light	LU	APCO 24			
12	Virginia Electric & Power	LU	APCO 16			
13						
14	AEP AFF - Assoc. Cos.	OS	APCO 20			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
			6,300	6,300	1
27,113	548,882	351,177	2,040	902,099	2
53,413	880,219	669,731	13,320	1,563,270	3
					4
104,789	728,117	1,927,762	372,899	3,028,778	5
		1,271		1,271	6
					7
6,928	29,158	92,167	15,363	136,688	8
9,657	105,556	220,683	65,563	391,802	9
					10
			413,448	413,448	11
13,021	293,629	411,836	683,457	1,388,922	12
					13
3,733,946		43,543,474		43,543,474	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad 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.

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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	AES Power, Inc.	OS	Note 1			
2	AIG Trading Corp	OS	Note 1			
3	Allegheny Power System	OS	OPCO 73			
4	Ameren Corporation	OS	IMPCO 67			
5	American Energy Solutions, Inc	OS	Note 1			
6	American Municipal Power, Oh	OS	OPCO 74			
7	AMOCO Energy Trading Corporation	OS	Note 1			
8	Aquila Power Corporation	OS	Note 1			
9	Arizona Public Service Company	OS	Note 1			
10	Arkansas Electric Cooperative Corp	OS	Note 1			
11	Associated Electric Coop	OS	Note 1			
12	Atlantic City Electric	OS	Note 1			
13	Atlantic Electric	OS	Note 1			
14	Austin Energy	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 of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
-94,208		-980,741		-980,741	1
154,524		5,359,191		5,359,191	2
3,052		82,354	7,251	89,605	3
2,860		103,845	8,124	111,969	4
-152		-2,653		-2,653	5
22,140		670,402	54,553	724,955	6
6,423		260,241	878	261,119	7
30,598		538,211	5,920	544,131	8
		-328,415		-328,415	9
-95		1,687		1,687	10
-680		-59,512	653	-58,859	11
-1,366		-34,817		-34,817	12
538		13,372		13,372	13
		-50		-50	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Avista Energy, Inc.	OS	Note 1			
2	AYP Energy, Inc.	OS	Note 1			
3	Baltimore Gas & Electric	OS	Note 1			
4	Cargill-Alliant LLC	OS	Note 1			
5	Carolina Power & Light	OS	APCO 24			
6	Central Illinois Light	OS	Note 1			
7	Central Louisiana Electric	OS	Note 1			
8	Cinergy Corporation	OS	OPCO 21			
9	Citizens Lehman Power Sales	OS	Note 1			
10	City of Radford	LF	Note 1			
11	City Water & Light	OS	Note 1			
12	CMS Marketing Services & Trading	OS	Note 1			
13	CNG Energy Services Corp.	OS	Note 1			
14	Coastal Electric Service	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

SALES FOR RESALE (Account 447) (Continued)

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

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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

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.
-9,184		-683,485	1,254	-682,231	1
28,092		527,977	8,654	536,631	2
5,134		183,045		183,045	3
28,565		1,600,288	272	1,600,560	4
10,827		336,763	52,151	388,914	5
-5,032		-134,656		-134,656	6
991		21,221		21,221	7
24,729		1,889,891	14,335	1,904,226	8
21,781		1,620,901	1,242	1,622,143	9
11,842		320,592	37,905	358,497	10
		-11		-11	11
-20,302		-1,232,628	1,255	-1,231,373	12
-7,021		-139,215	413	-138,802	13
		52		52	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad 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.
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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	Columbia Power Marketing	OS	Note 1			
2	Commonwealth Edison	OS	IMPCO 20			
3	Conagra Energy Services, Inc.	OS	Note 1			
4	Constellation Power Source, Inc.	OS	Note 1			
5	Constellation Power Source, Inc.	OS	Note 1			
6	Cook Inlet Energy Supply LP	OS	Note 1			
7	Coral Power	OS	Note 1			
8	Dayton Power & Light	OS	OPCO 36			
9	Delmarva Power & Light	OS	Note 1			
10	Detroit Edison	OS	Note 1			
11	Detroit Edison (Merchant Function)	OS	Note 1			
12	DTE Energy Trading	OS	Note 1			
13	Duke Power Company	OS	APCO 18			
14	Dupont Power Marketing, Inc.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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)
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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
19,291		943,960	2,204	946,164	1
290,242		11,558,355	706,053	12,264,408	2
-40,596		-1,467,570	219	-1,467,351	3
-152,096		-2,768,622	2,766	-2,765,856	4
116,421		2,759,825	11,479	2,771,304	5
77		-38,502		-38,502	6
-23,687		-536,223	2,473	-533,750	7
4,174		186,855	7,181	194,036	8
39,402		881,608		881,608	9
301		-34,951	46,614	11,663	10
3,665		-227,756		-227,756	11
-5,393		-146,378	2,946	-143,432	12
28,662		443,880	28,794	472,674	13
-42,807		665,359	1,810	667,169	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

SALES FOR RESALE (Account 447)

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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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Duquesne Light Company	OS	OPCO 33			
2	E Prime Inc.	OS	Note 1			
3	East Kentucky Power Cooperative	OS	KPCO 14			
4	ECR Adj	OS	Note 1			
5	El Paso Energy Marketing Company	OS	Note 1			
6	Electric Clearinghouse, Inc.	OS	Note 1			
7	Enerz Corporation	OS	Note 1			
8	Engage Energy	OS	Note 1			
9	Engelhard Power Marketing, Inc.	OS	Note 1			
10	Enron Power Marketing, Inc.	OS	Note 1			
11	Enserch Energy Services, Inc.	OS	Note 1			
12	Entergy Power Marketing Corporation	OS	Note 1			
13	Entergy Services, Inc.	OS	Note 1			
14	Equita	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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KPSC Case No. 99-149
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Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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,line 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.
54,642		2,041,120	106,527	2,147,647	1
-3,765		-278,125		-278,125	2
-359		17,834	4,861	22,695	3
78		21		21	4
-11,226		251,429	421	251,850	5
-26,462		-940,865	7,869	-932,996	6
14,236		-156,410		-156,410	7
19,719		1,289,846	2,496	1,292,342	8
-1,637		26,744		26,744	9
50,484		11,391,223	26,183	11,417,406	10
5,674		134,722	448	135,170	11
-45,890		-3,633,352	356	-3,632,996	12
1,128		18,646	7,286	25,932	13
14,224		371,665		371,665	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Federal Energy Sales	OS	Note 1			
2	First Energy	OS	OPCO 31			
3	First Energy Trading & Power Marketing	OS	Note 1			
4	Florida Power & Light	OS	Note 1			
5	General Public Utilities	OS	Note 1			
6	Griffin Energy Marketing LLC	OS	Note 1			
7	Houston Lighting & Power, Power Generat	OS	Note 1			
8	Idaho Power Company	OS	Note 1			
9	Illinois Power	OS	IMPCO 23			
10	Illnova Power Marketing, Inc.	OS	Note 1			
11	Indiana Municipal Power Agency	OS	IMPCO 74			
12	Indianapolis Power & Light	OS	IMPCO 21			
13	Kentucky Utilities	OS	OPCO 22			
14	KN Marketing Inc	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
		-1		-1	1
16,664		764,763	44,078	808,841	2
19,960		1,477,260	30	1,477,290	3
416		25,729	2,418	28,147	4
6,516		150,572		150,572	5
-634		-8,360	752	-7,608	6
		-97,005		-97,005	7
822		-35,840		-35,840	8
27,305		1,446,515	27,109	1,473,624	9
		-5,405,509		-5,405,509	10
14,434		364,894	79,464	444,358	11
871		48,196	2,893	51,089	12
-1,144		-10,655	156	-10,499	13
-63		-2,449		-2,449	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Koch Power Services, Inc	OS	Note 1			
2	LG&E Power Marketing, Inc.	OS	Note 1			
3	LG&E Utility Power Sales	OS	Note 1			
4	Louis Dreyfus Electric Power	OS	Note 1			
5	Louisville Gas &Electric	OS	IMPCO 79			
6	LTV-Illinois	OS	Note 1			
7	Merchant Energy Group of the Americas	OS	Note 1			
8	Michigan Electric Coordinated System	OS	IMPCO 68			
9	Michigan Public Power Agency	OS	Note 1			
10	Mid American Energy Company	OS	Note 1			
11	Midcon Power Services Corp	OS	Note 1			
12	Missouri Public Service	OS	Note 1			
13	Montana Power Trading & Marketing Co	OS	Note 1			
14	Morgan Stanley Group	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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KPSC Case No. 99-149
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
21,313		957,985	28,014	985,999	1
49,005		1,685,198	7,369	1,692,567	2
446		15,686	1,810	17,496	3
-53,206		-203,610	9,673	-193,937	4
12,798		285,574	2,129	287,703	5
		31,064	4,045	35,109	6
2,478		-280,910	321	-280,589	7
141,482		5,576,515	594,462	6,170,977	8
2,893		52,201	7,031	59,232	9
-2		-61		-61	10
-4,387		-115,671		-115,671	11
-1,370		-84,263	972	-83,291	12
		-1		-1	13
15,466		-386,569	25,166	-361,403	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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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) 04/30/1999	Year of Report Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	NESI Power Marketing	OS	Note 1			
2	New York State Energy & Gas Corp.	OS	Note 1			
3	NGE Generation, Inc.	OS	Note 1			
4	Niagara Mohawk Energy Marketing	OS	Note 1			
5	Noram Energy Services, Inc.	OS	Note 1			
6	North American Energy Conservation, Inc	OS	Note 1			
7	Northem Indiana Public Service Co.	OS	IMPCO 22			
8	Northem States Power	OS	Note 1			
9	NP Energy, Inc.	OS	Note 1			
10	OGE Energy Resources, Inc.	OS	Note 1			
11	Ogelthorpe Power Corporation	OS	Note 1			
12	Ohio Valley Electric Corp	OS	APCO 22			
13	Oklahoma Gas & Electric Company	OS	Note 1			
14	Ontario Hydro	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-17,336		-534,740	357	-534,383	1
-3,081		-116,284		-116,284	2
9,247		313,708		313,708	3
-17,006		-369,316		-369,316	4
-16,260		-450,292	3,621	-446,671	5
-8,861		-275,473		-275,473	6
5,724		156,227	7,280	163,507	7
7,434		150,080	55,707	205,787	8
8,337		179,829	1,596	181,425	9
-1,169		21,923	79	22,002	10
117		4,979	403	5,382	11
1,871		43,085	2,375	45,460	12
1,027		-3,818		-3,818	13
26		4,906	140	5,046	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	**2,610,278**	**80,005,857**	**4,784,828**	**87,400,963**	

Attachment
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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Pacific Gas & Electric Co.	OS	Note 1			
2	Pacificorp Power Marketing	OS	Note 1			
3	Pacificorp Power Marketing, Inc.	OS	Note 1			
4	PECO Energy, Inc.	OS	Note 1			
5	Pennsylvania Power & Light	OS	Note 1			
6	Pennsylvania\New Jersey\Maryland Pool	OS	Note 1			
7	PG&E Energy Trading - Power LP	OS	Note 1			
8	Phibro, Inc.	OS	Note 1			
9	Portland General Electric	OS	Note 1			
10	Portland General Electric	OS	Note 1			
11	Potomac Electric Power Co.	OS	Note 1			
12	Power Company of America	OS	Note 1			
13	Powerex	OS	Note 1			
14	Proliance Energy, LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-7,348		-889,497		-889,497	1
-130,622		-2,293,009	664	-2,292,345	2
71,544		1,703,771		1,703,771	3
97,082		1,813,651	1,495	1,815,146	4
-17,149		-746,456	9,270	-737,186	5
-52,069		-888,312	2,601	-885,711	6
78,706		1,740,326		1,740,326	7
-53		149,073		149,073	8
814		22,861		22,861	9
2,719		116,488		116,488	10
-3,411		-240,609		-240,609	11
20,938		-197,184	172	-197,012	12
		-1,768,502		-1,768,502	13
-4,374		-156,590		-156,590	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	PSEG Energy Technologies, Inc.	OS	Note 1			
2	Public Service Company of Colorado	OS	Note 1			
3	Public Service Company of Indiana	OS	IMPCO 24			
4	Public Electric Service & Gas	OS	Note 1			
5	Public Utility District No. 1 Chelan Cy	OS	Note 1			
6	Puget Sound Energy, Inc.	OS	Note 1			
7	QST Energy Trading, Inc.	OS	Note 1			
8	Questar Energy Trading	OS	Note 1			
9	Questar Energy Trading	OS	Note 1			
10	Rainbow Energy Marketing	OS	Note 1			
11	Richmond Power & Light	OS	IMPCO 70			
12	Scana Energy Mkt	OS	Note 1			
13	Scana Energy Mkt	OS	Note 1			
14	Sempra Energy Trading	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
8,061		134,808		134,808	1
1,195		54,019		54,019	2
316		36,554	2,513	39,067	3
61,299		1,615,925	949	1,616,874	4
		-1		-1	5
1,515					6
-41,165		-224,346		-224,346	7
77		1,519		1,519	8
-281		-345,869		-345,869	9
71		2,385	141	2,526	10
		-22		-22	11
-16,512		-648,388		-648,388	12
5,180		172,850	2,523	175,373	13
-135,393		-4,789,201		-4,789,201	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Sigeco/Hoosier	OS	Note 1			
2	Silicon Valley Power	OS	Note 1			
3	Snohomish County PUD No. 1	OS	Note 1			
4	Sonat Power Marketing	OS	Note 1			
5	South Carolina Electric & Gas	OS	Note 1			
6	South Jersey Energy	OS	Note 1			
7	Southern Company Services, Inc.	OS	Note 1			
8	Southern Energy Trading & Marketing	OS	Note 1			
9	Southern Indiana Gas & Electric	OS	Note 1			
10	SPSPOW	OS	Note 1			
11	Statoil Energy Trading, Inc.	OS	Note 1			
12	Tenaska Power Services Company	OS	Note 1			
13	Tennessee Valley Authority	OS	APCO 52			
14	Texas-New Mexico Power Company	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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KPSC Case No. 99-149
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
4,542		114,095	4,398	118,493	1
		-13,301		-13,301	2
305					3
7,778		-188,182	9,187	-178,995	4
384		-38,080	3,156	-34,924	5
-3,144		-16,485		-16,485	6
1,807		66,890	10,161	77,051	7
9,972		1,074,983	5,970	1,080,953	8
1,224		60,995	1,309	62,304	9
51		1,600		1,600	10
-57,147		-439,381		-439,381	11
-39		-1,521,458	4,573	-1,516,885	12
29,060		1,031,777	76,665	1,108,442	13
96		4,883	494	5,377	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	The Energy Authority	OS	Note 1			
2	Tractebel Energy Marketing	OS	Note 1			
3	Tuscon Electric Power	OS	Note 1			
4	Union Electric	OS	Note 1			
5	Utilicorp United Inc.	OS	Note 1			
6	Virginia Electric & Power	OS	APCO 16			
7	Vitol Gas & Electric, LLC	OS	Note 1			
8	W Plains Energy Kansas Power	OS	Note 1			
9	Wabash Valley	OS	IMPCO 76			
10	Washington Water Power	OS	Note 1			
11	Western Power Services	OS	Note 1			
12	Western Resources Generation Services	OS	Note 1			
13	Williams Energy Services Co.	OS	Note 1			
14	Wisconsin Electric Power	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
-5,792		-439,094	3,819	-435,275	1
-7,021		-434,836	534	-434,302	2
		-21		-21	3
		-25		-25	4
667					5
33,500		1,776,753	7,386	1,784,139	6
-12,590		-806,504	1,222	-805,282	7
-67		-2,541		-2,541	8
21,543		542,190	337	542,527	9
		4		4	10
1,314		26,141		26,141	11
1,624		-94,109	2,311	-91,798	12
19,880		-127,880	3,729	-124,151	13
30,542		-263,872	93,752	-170,120	14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Wisconsin Public Power	OS	Note 1			
2	Wisconsin Power Co.	OS	Note 1			
3	WPS Energy Services, Inc.	OS	Note 1			
4	WVP	OS	Note 1			
5	AES Power, Inc.	OS	Note 1			
6	Citizens Lehman Power Sales	OS	Note 1			
7	PECO Energy, Inc.	OS	Note 1			
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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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) 04/30/1999	Year of Report Dec. 31, 1998

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,line 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.
1,876		-2,632	8,818	6,186	1
-65		-50,336		-50,336	2
-1,528		-7,167		-7,167	3
4,814	24,717	92,855	19,786	137,358	4
129,571			740,740	740,740	5
213			205	205	6
15,209			120,262	120,262	7
					8
					9
					10
					11
					12
					13
					14
80,526	1,429,101	1,020,908	21,660	2,471,669	
4,802,751	1,181,177	78,984,949	4,763,168	84,929,294	
4,883,277	2,610,278	80,005,857	4,784,828	87,400,963	

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
310	1	j

Amounts in column J(Other Charges) from Page 311 Line 1 through Page 311.12 Line 4 Represent Transmission and Ancillary Charges Associated With Account 447

Page Number (a)	Item (row) Number (b)	Column Number (c)
310	9	c

NOTE 1 - AEP Power Sales Tariff, AEP Companies FERC Electric Tariff Original Volume 2

Page Number (a)	Item (row) Number (b)	Column Number (c)
310.12	5	j

Represents Coal Conversion Services and Related Transmission and Ancillary Charges

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	1,955,621	2,811,684
5	(501) Fuel	83,302,576	77,051,102
6	(502) Steam Expenses	2,405,561	2,580,010
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	249,461	304,160
10	(506) Miscellaneous Steam Power Expenses	4,242,518	2,166,771
11	(507) Rents	8,655	7,491
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	92,164,392	84,921,218
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,706,432	2,018,601
16	(511) Maintenance of Structures	740,954	1,109,889
17	(512) Maintenance of Boiler Plant	6,733,093	5,350,664
18	(513) Maintenance of Electric Plant	1,432,290	925,038
19	(514) Maintenance of Miscellaneous Steam Plant	1,217,879	612,154
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,830,648	10,016,346
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	103,995,040	94,937,564
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)		

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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) Maintenance 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	100,620,295	113,938,338
77	(556) System Control and Load Dispatching	800,398	1,129,986
78	(557) Other Expenses	1,729,525	
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	103,150,218	115,068,324
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	207,145,258	210,005,888
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,244,500	1,332,568
84	(561) Load Dispatching	373,070	271,868
85	(562) Station Expenses	227,340	225,250
86	(563) Overhead Lines Expenses	23,764	126,640
87	(564) Underground Lines Expenses	81	
88	(565) Transmission of Electricity by Others	-5,417,570	-2,414,545
89	(566) Miscellaneous Transmission Expenses	572,819	391,649
90	(567) Rents	-39,070	-73,670
91	TOTAL Operation (Enter Total of lines 83 thru 90)	-3,015,066	-140,240
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	376,407	382,315
94	(569) Maintenance of Structures	58,019	68,242
95	(570) Maintenance of Station Equipment	743,217	524,459
96	(571) Maintenance of Overhead Lines	1,137,899	1,150,547
97	(572) Maintenance of Underground Lines	15,201	9,887
98	(573) Maintenance of Miscellaneous Transmission Plant	20,675	14,393
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	2,351,418	2,149,843
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	-663,648	2,009,603
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	1,883,469	2,383,044

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	385,911	236,314
106	(582) Station Expenses	180,929	120,188
107	(583) Overhead Line Expenses	246,248	538,307
108	(584) Underground Line Expenses	13,054	12,691
109	(585) Street Lighting and Signal System Expenses	18,197	18,944
110	(586) Meter Expenses	946,772	971,124
111	(587) Customer Installations Expenses	372,107	465,980
112	(588) Miscellaneous Expenses	2,990,273	2,422,313
113	(589) Rents	206,536	350,210
114	TOTAL Operation (Enter Total of lines 103 thru 113)	7,243,496	7,519,115
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	707,759	691,567
117	(591) Maintenance of Structures	27,045	88,847
118	(592) Maintenance of Station Equipment	600,678	412,030
119	(593) Maintenance of Overhead Lines	11,762,323	7,709,592
120	(594) Maintenance of Underground Lines	117,239	149,049
121	(595) Maintenance of Line Transformers	680,500	739,045
122	(596) Maintenance of Street Lighting and Signal Systems	33,147	46,759
123	(597) Maintenance of Meters	132,756	171,274
124	(598) Maintenance of Miscellaneous Distribution Plant	329,009	300,536
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	14,390,456	10,308,699
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	21,633,952	17,827,814
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	186,476	330,622
130	(902) Meter Reading Expenses	1,672,571	1,615,992
131	(903) Customer Records and Collection Expenses	3,930,485	4,609,202
132	(904) Uncollectible Accounts	1,389,099	1,496,337
133	(905) Miscellaneous Customer Accounts Expenses	600,528	378,391
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	7,779,159	8,430,544
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	203,018	330,594
138	(908) Customer Assistance Expenses	3,297,675	2,920,704
139	(909) Informational and Instructional Expenses	34,703	18,173
140	(910) Miscellaneous Customer Service and Informational Expenses	1,362,621	573,709
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	4,898,017	3,843,180
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	8,615	3,072
146	(913) Advertising Expenses	91,125	82,763
147	(916) Miscellaneous Sales Expenses	240,277	324,067
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	340,017	409,902
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	2,708,319	4,089,958
152	(921) Office Supplies and Expenses	4,686,275	4,240,926
153	(Less) (922) Administrative Expenses Transferred-Credit	41,658	9,694

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	553,158	668,934
156	(924) Property Insurance	479,715	277,569
157	(925) Injuries and Damages	2,029,161	3,620,440
158	(926) Employee Pensions and Benefits	6,744,614	6,487,247
159	(927) Franchise Requirements	120,082	118,501
160	(928) Regulatory Commission Expenses	295,634	281,285
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	114,105	213,681
163	(930.2) Miscellaneous General Expenses	2,555,108	2,270,774
164	(931) Rents	334,185	267,509
165	TOTAL Operation (Enter Total of lines 151 thru 164)	20,578,698	22,527,130
166	Maintenance		
167	(935) Maintenance of General Plant	1,889,664	1,941,956
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	22,468,362	24,469,086
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	263,601,117	266,996,017

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employes on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/1998
2. Total Regular Full-Time Employees	690
3. Total Part-Time and Temporary Employees	2
4. Total Employees	692

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
320	5	b

ACCOUNT 50199

Includes a credit pertaining to Deferred Fuel Costs of $448,760 applicable to the current year.

Page Number (a)	Item (row) Number (b)	Column Number (c)
320	5	c

ACCOUNT 50199

Includes a credit pertaining to Deferred Fuel Costs of $1,304,170 applicable to the previous year.

Page Number (a)	Item (row) Number (b)	Column Number (c)
320	162	b

Charges to Account 930.1 - General Advertising Expenses, include costs for advertising as usually defined (i.e., newspaper, radio and television advertisements), as well as other public affairs expenditures of a general informational or educational nature which are included in this account in accordance with FERC accounting requirements. Of the total charged to this account in 1998 $17,194 was related to advertising as usually defined and $96,911 was related to other activities.

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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP Generating Co (3)	RQ	AEG 1	N/A	N/A	N/A
2						
3	Indianapolis Power & Light	IF	IMPCO 21	N/A	N/A	N/A
4						
5	AEP System Power Pool (4)	OS	APCO 20	N/A	N/A	N/A
6	AES Power Inc	OS	(3)	N/A	N/A	N/A
7	Allegheny Power System	OS	(3)	N/A	N/A	N/A
8	Ameren Corporation	OS	IMPCO 67	N/A	N/A	N/A
9	American Energy Solutions	OS	(3)	N/A	N/A	N/A
10	American Municipal Power	OS	OPCO 74	N/A	N/A	N/A
11	AMOCO Energy Trading Corp	OS	(3)	N/A	N/A	N/A
12	Aquila	OS	(3)	N/A	N/A	N/A
13	Associated Electric Coop, Inc	OS	(3)	N/A	N/A	N/A
14	Atlantic Electric	OS	(3)	N/A	N/A	N/A
	Total					

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Order Dated April 22, 1999
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
2,629,934				67,291,086		67,291,086	1
							2
271				3,473		3,473	3
							4
670,539				9,672,934		9,672,934	5
-1,015				8,101		8,101	6
3,812				140,227		140,227	7
3,647				163,887		163,887	8
7				141		141	9
16				401		401	10
336				11,431		11,431	11
3,893				168,816		168,816	12
174				6,777		6,777	13
				12		12	14
3,899,973				100,620,299		100,620,299	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	Avista Energy Inc	OS	(3)	N/A	N/A	N/A
2	AYP Energy Inc	OS	(3)	N/A	N/A	N/A
3	Cargill-Alliant, LLC	OS	(3)	N/A	N/A	N/A
4	Carolina Power & Light	OS	APCO 24	N/A	N/A	N/A
5	Central Illinois Light	OS	(3)	N/A	N/A	N/A
6	Cinergy Corporation	OS	OPCO 21	N/A	N/A	N/A
7	Citizens Lehman Power Sales	OS	(3)	N/A	N/A	N/A
8	City Of Holland	OS	(3)	N/A	N/A	N/A
9	CMS Marketing	OS	(3)	N/A	N/A	N/A
10	CNG Energy Services	OS	(3)	N/A	N/A	N/A
11	Columbia Power Marketing	OS	(3)	N/A	N/A	N/A
12	Commonwealth Edison Co	OS	IMPCO 20	N/A	N/A	N/A
13	Conagra Energy Services	OS	(3)	N/A	N/A	N/A
14	Conoco Power Marketing	OS	(3)	N/A	N/A	N/A
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
377				17,286		17,286	1
23,776				483,670		483,670	2
12,006				670,243		670,243	3
24,235				624,589		624,589	4
912				20,973		20,973	5
8,239				224,131		224,131	6
2,547				79,647		79,647	7
11				847		847	8
2,381				163,372		163,372	9
581				13,279		13,279	10
436				30,068		30,068	11
29,600				2,285,068		2,285,068	12
2,302				96,320		96,320	13
				63		63	14
3,899,973				100,620,299		100,620,299	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Constellation Power Source	OS	(3)	N/A	N/A	N/A
2	Coral Power	OS	(3)	N/A	N/A	N/A
3	Dayton Power & Light Co	OS	OPCO 36	N/A	N/A	N/A
4	Delmarva Power & Light	OS	(3)	N/A	N/A	N/A
5	Detroit Edison	OS	(3)	N/A	N/A	N/A
6	DTE Energy Trading, Inc	OS	(3)	N/A	N/A	N/A
7	Duke Power Co	OS	APCO 18	N/A	N/A	N/A
8	Duquesne	OS	OPCO 33	N/A	N/A	N/A
9	Electric Clearinghouse Inc	OS	(3)	N/A	N/A	N/A
10	El Paso Power Services Co	OS	(3)	N/A	N/A	N/A
11	Enerz Corp	OS	(3)	N/A	N/A	N/A
12	Engage Energy	OS	(3)	N/A	N/A	N/A
13	Engelhard Power Marketing Inc	OS	(3)	N/A	N/A	N/A
14	Enron Power Marketing Inc	OS	(3)	N/A	N/A	N/A
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
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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.
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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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
4,232				135,730		135,730	1
1,751				28,168		28,168	2
13,022				303,577		303,577	3
				24		24	4
400				23,488		23,488	5
8,611				232,642		232,642	6
43,434				1,422,671		1,422,671	7
11,497				229,148		229,148	8
12,428				1,506,440		1,506,440	9
856				46,215		46,215	10
351				10,185		10,185	11
2,135				89,070		89,070	12
				12		12	13
44,929				1,956,221		1,956,221	14
3,899,973				100,620,299		100,620,299	

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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) 04/30/1999	Year of Report Dec. 31, 1998

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.

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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 the designated unit.

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Entergy	OS	(3)	N/A	N/A	N/A
2	Entergy Power Marketing Corp	OS	(3)	N/A	N/A	N/A
3	First Energy	OS	OPCO 31	N/A	N/A	N/A
4	First Energy Trading & Power Marketing	OS	(3)	N/A	N/A	N/A
5	Florida Power & Light	OS	(3)	N/A	N/A	N/A
6	General Public Utilities	OS	(3)	N/A	N/A	N/A
7	Griffin Energy Marketing	OS	(3)	N/A	N/A	N/A
8	Illinois Power Co	OS	IMPCO 23	N/A	N/A	N/A
9	Indiana Municipal Power Agency	OS	(3)	N/A	N/A	N/A
10	Indianapolis Power & Light	OS	IMPCO 21	N/A	N/A	N/A
11	Kentucky Utilities	OS	OPCO 22	N/A	N/A	N/A
12	Koch	OS	(3)	N/A	N/A	N/A
13	LGE Power Marketing	OS	(3)	N/A	N/A	N/A
14	LG&E Utilities Power Sales	OS	(3)	N/A	N/A	N/A
	Total					

Attachment
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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
165				11,631		11,631	1
5,382				315,749		315,749	2
1,825				67,132		67,132	3
447				20,744		20,744	4
3,716				319,113		319,113	5
				1		1	6
192				5,410		5,410	7
2,454				139,500		139,500	8
102				8,242		8,242	9
52,355				1,109,103		1,109,103	10
3,189				64,317		64,317	11
2,841				89,444		89,444	12
5,574				310,263		310,263	13
10,949				367,334		367,334	14
3,899,973				100,620,299		100,620,299	

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Order Dated April 22, 1999
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	Louis Dreyfus Electric Power	OS	(3)	N/A	N/A	N/A
2	Louisville Gas & Electric	OS	IMPCO 70	N/A	N/A	N/A
3	Merchant Energy Group Of the Americas	OS	(3)	N/A	N/A	N/A
4	Michigan Electric Coordinated System	OS	IMPCO 68	N/A	N/A	N/A
5	Michigan Public Power Agency	OS	(3)	N/A	N/A	N/A
6	Mid American Energy Company	OS	(3)	N/A	N/A	N/A
7	Mid American Natural Resources	OS	(3)	N/A	N/A	N/A
8	Midcon Power Services	OS	(3)	N/A	N/A	N/A
9	Missouri Public Service	OS	(3)	N/A	N/A	N/A
10	Missouri Public Service Power Marketin	OS	(3)	N/A	N/A	N/A
11	Morgan Stanley	OS	(3)	N/A	N/A	N/A
12	National Power Energy Inc	OS	(3)	N/A	N/A	N/A
13	NESI Power Marketing	OS	(3)	N/A	N/A	N/A
14	NGE Generation	OS	(3)	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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.
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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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
4,737				121,050		121,050	1
13,309				312,157		312,157	2
304				15,929		15,929	3
7,431				501,580		501,580	4
1,315				91,985		91,985	5
				2,473		2,473	6
72				2,721		2,721	7
				1		1	8
489				78,408		78,408	9
				2,414		2,414	10
4,060				282,117		282,117	11
				83		83	12
118				2,650		2,650	13
48				1,500		1,500	14
3,899,973				100,620,299		100,620,299	

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TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - *for short-term service.* Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Niagara Mohawk Energy Marketing, Inc	OS	(3)	N/A	N/A	N/A
2	Noram Energy Services	OS	(3)	N/A	N/A	N/A
3	North American Energy	OS	(3)	N/A	N/A	N/A
4	Northern Indiana Public Serv Co	OS	IMPCO 22	N/A	N/A	N/A
5	Northern States Power	OS	(3)	N/A	N/A	N/A
6	N.Y. State Energy & Gas Co	OS	(3)	N/A	N/A	N/A
7	OGE Energy Resources	OS	(3)	N/A	N/A	N/A
8	Ohio Valley Electric Corp	OS	APCO 22	N/A	N/A	N/A
9	Pacific Gas & Electric Co	OS	(3)	N/A	N/A	N/A
10	Pacificorp	OS	(3)	N/A	N/A	N/A
11	Pacificorp Power Marketing	OS	(3)	N/A	N/A	N/A
12	Pennsylvania Power & Light	OS	(3)	N/A	N/A	N/A
13	Penn/New Jersey/Maryland Pool	OS	(3)	N/A	N/A	N/A
14	PG&E Energy Trading	OS	(3)	N/A	N/A	N/A
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
293				37,155		37,155	1
3,122				244,836		244,836	2
240				5,408		5,408	3
1,114				32,064		32,064	4
1,602				76,880		76,880	5
				44		44	6
57				3,055		3,055	7
34				319		319	8
484				9,626		9,626	9
728				15,444		15,444	10
2,019				65,273		65,273	11
17,692				963,112		963,112	12
3				70		70	13
385				18,760		18,760	14
3,899,973				100,620,299		100,620,299	

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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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	Phibro	OS	(3)	N/A	N/A	N/A
2	Philadelphia Electric Co	OS	(3)	N/A	N/A	N/A
3	PJM - Direct Sales	OS	(3)	N/A	N/A	N/A
4	Potomac Electric Power Co	OS	(3)	N/A	N/A	N/A
5	Power Company Of America	OS	(3)	N/A	N/A	N/A
6	Proliance Energy	OS	(3)	N/A	N/A	N/A
7	Public Service Electric & Gas	OS	(3)	N/A	N/A	N/A
8	QST Energy Trading Inc	OS	(3)	N/A	N/A	N/A
9	Rainbow Energy Marketing	OS	(3)	N/A	N/A	N/A
10	Scana Energy Marketing Inc	OS	(3)	N/A	N/A	N/A
11	Sempra Energy Trading	OS	(3)	N/A	N/A	N/A
12	Sonat Power Marketing	OS	(3)	N/A	N/A	N/A
13	South Carolina Electric & Gas	OS	(3)	N/A	N/A	N/A
14	Southern Company Services	OS	(3)	N/A	N/A	N/A
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
48				1,155		1,155	1
8,234				339,678		339,678	2
11,299				439,106		439,106	3
3,728				121,272		121,272	4
57				-20,088		-20,088	5
96				2,180		2,180	6
4,577				150,399		150,399	7
96				2,270		2,270	8
71				5,295		5,295	9
48				13,505		13,505	10
498				16,556		16,556	11
2,435				93,497		93,497	12
8,536				195,646		195,646	13
2,372				136,509		136,509	14
3,899,973				100,620,299		100,620,299	

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TC (1st Set)
Order Dated April 22, 1999
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern Energy Trading & Marketing	OS	(3)	N/A	N/A	N/A
2	Stand Energy Inc	OS	(3)	N/A	N/A	N/A
3	Statoil Energy Trading Inc	OS	(3)	N/A	N/A	N/A
4	Tenaska Power Services Company	OS	(3)	N/A	N/A	N/A
5	Tennessee Valley Authority	OS	APCO 52	N/A	N/A	N/A
6	The Energy Authority	OS	(3)	N/A	N/A	N/A
7	Tractabel Energy Marketing	OS	(3)	N/A	N/A	N/A
8	UtiliCorp United, Inc	OS	(3)	N/A	N/A	N/A
9	Virginia Electric & Power	OS	APCO 16	N/A	N/A	N/A
10	Vitol Gas & Electric	OS	(3)	N/A	N/A	N/A
11	Wabash Valley Dump Power	OS	IMPCO 76	N/A	N/A	N/A
12	Western Resources Generation Services	OS	(3)	N/A	N/A	N/A
13	Williams Energy Services	OS	(3)	N/A	N/A	N/A
14	Wisconsin Electric Power Co	OS	(3)	N/A	N/A	N/A
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
9,844				360,493		360,493	1
				1		1	2
483				19,949		19,949	3
5,071				100,099		100,099	4
81,057				2,785,890		2,785,890	5
1,111				60,860		60,860	6
3,358				235,337		235,337	7
96				4,428		4,428	8
19,532				851,514		851,514	9
4,217				199,164		199,164	10
10				488		488	11
3,584				91,474		91,474	12
4,377				317,588		317,588	13
2,189				76,350		76,350	14
3,899,973				100,620,299		100,620,299	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	Wisconsin Public Power, Inc	OS	(3)	N/A	N/A	N/A
2	WPS Energy Services	OS	(3)	N/A	N/A	N/A
3						
4	East Kentucky Power Coop	OS	KPCO 14	N/A	N/A	N/A
5						
6	Loop Regulation Energy			N/A	N/A	N/A
7	Misc Adjustments to MWH (5)					
8						
9						
10						
11						
12						
13						
14						
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.

In column (c), identify the FERC Rate Schedule Number or tariffs, 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.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding 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 rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
946				61,072		61,072	1
192				3,954		3,954	2
							3
2,976				67,256		67,256	4
							5
5,398				11,872		11,872	6
1,927							7
							8
							9
							10
							11
							12
							13
							14
3,899,973				100,620,299		100,620,299	

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
326	1	a

(3) AEP Power Sales Tariff - AEP Companies FERC Electric Tariff Original Volume 2.

Page Number (a)	Item (row) Number (b)	Column Number (c)
326	1	c

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

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

Page Number (a)	Item (row) Number (b)	Column Number (c)
326	5	a

(4) Receipts of power from the members of the AEP System Power Pool (See Note 2) governed by the terms of the interconnection agreement dated July 6, 1951, as amended.

Page Number (a)	Item (row) Number (b)	Column Number (c)
326	5	b

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

Page Number (a)	Item (row) Number (b)	Column Number (c)
326.8	7	a

(5) OVEC surplus and supplemental losses (net)	0
Loop regulation energy difference	2,843
Non-displacement payback losses	75
Purchased power transferred losses	-14,067
Unit power losses (net)	4,880
AEP System Power Pool losses (net)	2,104
Unit Energy and Miscellaneous	6,092
TOTAL	1,927

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(Next Page is 328)

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/1999	Year of Report Dec. 31, 1998

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

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				
2	Virginia Electric & Power Co.	Various	Various	OS
3	Wabash Valley Power Assn.	Various	Various	LF
4	Blue Ridge Agency	PSI Energy	Blue Ridge Agency	LF
5	Allegheny Power Systems	Various	Various	OS
6	Ameren	Various	Various	OS
7	AMOCO	Various	Various	OS
8	AMP-Ohio, Inc.	Various	Various	OS
9	Aquila, Inc.	Various	Various	OS
10	Avista	Various	Various	OS
11	AYP Energy, Inc.	Various	Various	OS
12	Cargill Alliant	Various	Various	OS
13	CNG Energy Services Corp	Various	Various	OS
14	Columbia Power Marketing	Various	Various	OS
15	Commonwealth Edison	Various	Various	OS
16	Cinergy	Various	Various	OS
17	Citizens Lehman	Various	Various	OS
	TOTAL			

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

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.

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)	
						1
See Footnotes	Various	Various		79,906	80,385	2
IMPCo 76	Various	Various		62,707	60,437	3
See Footnotes	Various	Blue Ridge		80,049	94,978	4
OPCo 73	Various	Various		3,013	3,040	5
See Footnotes	Various	Various		13	13	6
See Footnotes	Various	Various		435	430	7
OPCo 74	Various	Various		67,577	67,529	8
See Footnotes	Various	Various		9,511	9,516	9
See Footnotes	Various	Various		1,022	1,022	10
See Footnotes	Various	Various		4,554	4,554	11
See Footnotes	Various	Various		4,464	4,464	12
See Footnotes	Various	Various		10	10	13
See Footnotes	Various	Various		167	167	14
IMPCo 73	Various	Various		327,104	327,200	15
OPCo 21	Various	Various		34,657	35,202	16
See Footnotes	Various	Various		745	741	17
			0	1,723,922	1,723,922	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
				1
	330,452	33,958	364,410	2
	299,092	47,484	346,576	3
	302,047	60,522	362,569	4
	32,522	2,518	35,040	5
	116	6	122	6
	8,068	200	8,268	7
	262,032	43,955	305,987	8
	113,821	6,982	120,803	9
	12,248	511	12,759	10
	43,428	3,144	46,572	11
	50,293	3,193	53,486	12
	71	4	75	13
	943	77	1,020	14
	1,514,663	169,071	1,683,734	15
	190,744	13,582	204,326	16
	3,156	321	3,477	17
0	8,966,142	879,302	9,845,444	

Attachment
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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/1999	Year of Report Dec. 31, 1998

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

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	Constellation Power Source	Various	Various	OS
2	CMS Marketing Serv & Trading	Various	Various	OS
3	Coral Power, LLC	Various	Various	OS
4	Carolina Power & Light Company	Various	Various	OS
5	Cleveland Public Power	Various	Various	OS
6	Dayton Power & Light	Various	Various	OS
7	Detroit Edison	Various	Various	OS
8	DTE Energy Trading	Various	Various	OS
9	Duke Power Co.	Various	Various	OS
10	Electric Clearinghouse, Inc.	Various	Various	OS
11	East Kentucky Power Coop	Various	Various	OS
12	El Paso	Various	Various	OS
13	Engage Energy	Various	Various	OS
14	Enron Power Marketing, Inc.	Various	Various	OS
15	Entergy Power Marketing	Various	Various	OS
16	Federal Energy Sales	Various	Various	OS
17	First Energy	Various	Various	OS
	TOTAL			

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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) 04/30/1999	Year of Report Dec. 31, 1998

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.
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.
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.

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.
See Footnotes	Various	Various		53,821	53,825	1
See Footnotes	Various	Various		630	630	2
See Footnotes	Various	Various		968	968	3
APCo 24	Various	Various		3,995	3,942	4
See Footnotes	Various	Various		43,878	43,856	5
OPCo 36	Various	Various		2,801	2,810	6
See Footnotes	Various	Various		9,059	8,775	7
See Footnotes	Various	Various		5,846	5,961	8
APCo 18	Various	Various		2,315	2,446	9
See Footnotes	Various	Various		40,826	40,800	10
KPCo 14	Various	Various		7,975	7,975	11
See Footnotes	Various	Various		230	232	12
See Footnotes	Various	Various		30,087	30,092	13
See Footnotes	Various	Various		18,878	18,928	14
See Footnotes	Various	Various		342	330	15
See Footnotes	Various	Various		1,169	1,169	16
See Footnotes	Various	Various		52	52	17
			0	1,723,922	1,723,922	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
	412,157	32,420	444,577	1
	6,438	544	6,982	2
	5,985	463	6,448	3
	23,725	2,201	25,926	4
	152,540	10,737	163,277	5
	15,427	1,332	16,759	6
	298,946	21,514	320,460	7
	33,576	2,773	36,349	8
	35,906	1,854	37,760	9
	991,690	60,528	1,052,218	10
	35,369	3,847	39,216	11
	2,029	113	2,142	12
	129,762	8,630	138,392	13
	136,703	10,072	146,775	14
	1,403	159	1,562	15
	8,913	583	9,496	16
	6,047	73	6,120	17
0	8,966,142	879,302	9,845,444	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

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	Hoosier Energy Resources	Various	Various	OS
2	Illinois Power Company	Various	Various	OS
3	Indiana Municipal Power Agency	Various	Various	OS
4	Koch Power Services	Various	Various	OS
5	Louisville Gas & Electric	Various	Various	OS
6	LG&E Power Marketing, Inc.	Various	Various	OS
7	Louis Dreyfus Electric Power, Inc.	Various	Various	OS
8	MECS	Various	Various	OS
9	Merchant Energy Group of the Americas	Various	Various	OS
10	Morgan Stanley & Co., Inc.	Various	Various	OS
11	NESI Power Marketing	Various	Various	OS
12	Northern Indiana Public Service Co.	Various	Various	OS
13	Noram Energy Services	Various	Various	OS
14	NPE Energy Inc	Various	Various	OS
15	Power Company Of America	Various	Various	OS
16	Philadelphia Electric Company	Various	Various	OS
17	QST	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

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.

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.
See Footnotes	Various	Various		171	171	1
See Footnotes	Various	Various		5,848	5,850	2
See Footnotes	Various	Various		42,634	42,313	3
See Footnotes	Various	Various		10,519	10,504	4
See Footnotes	Various	Various		288	288	5
See Footnotes	Various	Various		238	244	6
See Footnotes.	Various	Various		1,844	1,842	7
See Footnotes	Various	Various		24,547	24,575	8
See Footnotes	Various	Various		376	376	9
See Footnotes	Various	Various		24,633	25,284	10
See Footnotes	Various	Various		15,368	15,368	11
IMPCo 22	Various	Various		75	75	12
See Footnotes	Various	Various		580	580	13
See Footnotes	Various	Various		119	119	14
See Footnotes	Various	Various		638	638	15
See Footnotes	Various	Various		597,180	597,527	16
See Footnotes	Various	Various		51	51	17
			0	1,723,922	1,723,922	

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
	791	141	932	1
	86,101	4,460	90,561	2
	170,186	14,881	185,067	3
	64,736	5,199	69,935	4
	1,389	125	1,514	5
	2,288	158	2,446	6
	19,730	934	20,664	7
	438,451	26,596	465,047	8
	1,591	194	1,785	9
	61,403	20,166	81,569	10
	40,175	6,645	46,820	11
	585	34	619	12
	10,009	331	10,340	13
	955	78	1,033	14
	3,277	301	3,578	15
	2,300,150	225,927	2,526,077	16
	1,532	47	1,579	17
0	8,966,142	879,302	9,845,444	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

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	Rainbow Energy Marketing Corp.	Various	Various	OS
2	Public Service Electric & Gas	Various	Various	OS
3	Pennsylvania Power & Light	Various	Various	OS
4	Sonat Power Marketing	Various	Various	OS
5	Stand Power Marketing	Various	Various	OS
6	Pacificorp Power Marketing	Various	Various	OS
7	Southern Energy Trading & Marketing	Various	Various	OS
8	North Carolina Electric Membership Corp.	AEP System	See Footnotes	LF
9	Vitol Gas & Electric	Various	Various	OS
10	Williams Energy Services	Various	Various	OS
11	The Energy Authority	Various	Various	OS
12	Tenaska Power Services	Various	Various	OS
13	Tractabel Energy Marketing	Various	Various	OS
14	TVA	Various	Various	OS
15	Various (7)	Various	Various	OS
16				
17	Losses Associated With Wheeling Power			
	TOTAL			

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

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.

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)	
See Footnotes	Various	Various		2,456	2,456	1
See Footnotes	Various	Various		51	51	2
See Footnotes	Various	Various		9,811	9,714	3
See Footnotes	Various	Various		3,105	3,104	4
See Footnotes	Various	Various		7,886	7,884	5
See Footnotes	Various	Various		423	423	6
See Footnotes	Various	Various		4,454	4,460	7
See Footnotes	Various	Various		51,869	51,820	8
APCo 16	Various	Various		959	959	9
See Footnotes	Various	Various		1,178	1,178	10
See Footnotes	Various	Various		205	205	11
See Footnotes	Various	Various		2,430	2,426	12
See Footnotes	Various	Various		51	51	13
See Footnotes	Various	Various		313	313	14
See Footnotes	Various	Various		592	594	15
						16
				14,224		17
			0	1,723,922	1,723,922	

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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.
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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.
	20,678	1,206	21,884	1
	1,565	139	1,704	2
	62,786	5,857	68,643	3
	40,280	2,558	42,838	4
	36,729	2,563	39,292	5
	2,520	377	2,897	6
	29,947	2,123	32,070	7
	60,295	10,775	71,070	8
	6,920	531	7,451	9
	20,695	1,110	21,805	10
	1,566	98	1,664	11
	8,260	1,148	9,408	12
	858	24	882	13
	2,007	145	2,152	14
	7,375	1,060	8,435	15
				16
				17
0	8,966,142	879,302	9,845,444	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
328	2	a

The Respondent, Columbus Southern Power, Indiana Michigan Power Company, Ohio Power Company, and Appalachian Power Company are associated companies and are parties to the Transmission Agreement dated April 1, 1984, as amended. Pursuant to the terms of the Transmission Agreement, American Electric Power Service Corporation serves as agent and the parties pool their investment share of revenues and costs in proportion to the respective member's load ratio. The Revenues in column (m) represent the Respondent's member load ratio share of Transmission Service charges for those transactions.

328	2	e

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.

328.3	8	c

Various points of AEP System Interconnections with Virginia Power, Duke Power, and Carolina Power & Light. Figures represent the company's member load ratio of AEP System totals.

328.3	8	d

Earliest termination date - December 31, 2010.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	AEP System Trans Agree					-6,029,195	-6,029,195
2	East Kentucky Coop					207,765	207,765
3	Ameren			6,999	2,121		9,120
4	APS	12,035	12,035	51,571	9,890		61,461
5	Bonneville Power Admin	324	324	31,290	2,393		33,683
6	Brazos Electric Coop				17		17
7	Chelan County, Wa	1	1	7			7
8	Cinergy	70,099	70,099	153,534	46,215		199,749
9	San Antonio City Pub Sv				99		99
10	City of Austin			5			5
11	City of Garland				2		2
12	ComEd	6,429	6,429	12,438			12,438
13	Consumers Energy(MECS)	182	182	708	219		927
14	Central & South West	102	102	415	20		435
15	Duke Power	1,892	1,892	8,295	7,545		15,840
16	Duke Power (To: NCEMC)						
	TOTAL	94,895	94,895	329,925	73,935	-5,821,430	-5,417,570

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY: Magawatt-hours Received (b)	TRANSFER OF ENERGY: Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	East Kentucky Power	293	293	899			899
2	Entergy	54	54	544	165		709
3	Ercot ISO	2,010	2,010	250	52		302
4	First Energy	398	398	1,009			1,009
5	Garland Power & Light				1		1
6	Houston Lighting & Powr	2	2	28			28
7	Lower Colorado River				30		30
8	PJM Pool			7,094	2,752		9,846
9	PECO	3	3	11			11
10	Southwest Power Pool			3,779			3,779
11	Texas-New Mexico Power				9		9
12	TVA	1,071	1,071	49,114	1,357		50,471
13	VEP (To: NCEMC)						
14	VEP			1,830	1,048		2,878
15	KU			101			101
16	OVEC			4			4
	TOTAL	94,895	94,895	329,925	73,935	-5,821,430	-5,417,570

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
332	1	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 investment in high voltage transmission facilities (138kv and above) and share the cost of ownership in proportion to the respective member's load ratio. As such there is no transfer of energy and some parties receive credits designated by brackets"()" which are recorded in Account 565.

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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	923,971
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	68,500
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	88,073
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Non-Energy T & D Business	173,311
7	Interest Cost on AEP Borrowed Capital	70,020
8	Load Research - Time of Day	24,456
9	Fleet Management Activities	54,294
10	Activities Supporting East Central Area Reliability	14,083
11	Management Development Activities	31,058
12	ABMS Enhancements	253,302
13	Financial Integration Projects	62,753
14	AEP Corporate Services	830,126
15	Activities Supporting North American Electric Reliab	12,655
16	Consulting Expenses - New Software Projects	12,118
17	Business Related Travel Expenses	16,762
18	Software Chgs Capitalized Out Of Expense Work Orders	-96,736
19	Other Items (98) Under $5,000	16,362
20		
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46	TOTAL	2,555,108

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) 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 ***pi ant s6baccount, 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 sub-account, 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)	Amortization of Limited Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant		581		581
2	Steam Product Plant	9,566,276			9,566,276
3	Nuclear Production Plant				
4	Hydraulic Production Plant-Conventional				
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant				
7	Transmission Plant	5,404,583			5,404,583
8	Distribution Plant	12,115,877			12,115,877
9	General Plant	951,308	3,120		954,428
10	Common Plant-Electric				
11	TOTAL	28,038,044	3,701		28,041,745

B. Basis for Amortization Charges

The $3,701 represents amortization of individual Franchises and Consents and Leasehold Improvements over their estimated remaining lives.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production	257,330					
13	Transmission	324,486					
14	Distribution	350,047					
15	General	37,703					
16							
17							
18							
19							
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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
336	12	b

NOTE (A)

Depreciation was accrued monthly on functional composite bases at the above rates per annum on electric Plant In Service Less Land and Land Rights, Intangibles, Improvements to Leased Property and Automotive Equipment as reflected by the Book of Accounts.

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

NOTE (B)

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

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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges account. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425): Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions: Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	425 - MISCELLANEOUS AMORTIZATION	
2	' TOTAL 425	
3		
4	426 - OTHER INCOME DEDUCTIONS	
5	' 426.0 MISCELLANEOUS INCOME DEDUCTIONS	
6	' Miscellaneous	4,013
7		
8	' Total 426.0	4,013
9		
10	' 426.1 DONATIONS	
11	' Educational	
12	' Pikeville College	27,000
13	' Miscellaneous	37,161
14	' Medical - Miscellaneous	13,050
15	' Community	
16	' United Way	12,850
17	' Miscellaneous	53,930
18	' Other Donations - Miscellaneous	96,065
19		
20	' Total 426.1	240,056
21		
22	' 426.3 PENALTIES	
23	' Internal Revenue Service	1,011
24		
25	' Total 426.3	1,011
26		
27	' 426.4 EXPENDITURES FOR CERTAIN CIVIC,	
28	' POLITICAL, & RELATED ACTIVITIES	
29	' Lobbying Expenses of Parent Co.	
30	' - Edison Electric Institute	50,976
31	' - Miscellaneous	35,193
32	' Transportation	7,775
33	' Labor	89,434
34	' Miscellaneous Expenses	119,934
35		
36	' Total 426.4	303,312
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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges account. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425): Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions: Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	426.5 OTHER DEDUCTIONS	
2	Club Dues & Memberships	10,560
3	HMS Partners LTD of Ohio	324,173
4	Options	82,067,944
5	Customer Financing Program	370,011
6		
7	Total 426.5	82,772,688
8		
9	431 OTHER INTEREST EXPENSE	
10		
11	Short-Term Notes - Various	371,139
12	Commercial Paper - Various	2,012,934
13	Lines of Credit Fees	70,683
14	Customer Deposits	226,416
15		
16	TOTAL 431	2,681,172
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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	FERC Assesment 97-98		171,759	171,759	
2					
3	FERC Assesment 98-99		59,751	59,751	
4					
5	KY PSC #96-489 Recover Costs of Clean Air Act		32,369	32,369	
6					
7	Miscellaneous		31,755	31,755	
8					
9					
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12					
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46	TOTAL		295,634	295,634	

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REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Electric	928	171,759					1
							2
Electric	928	59,751					3
							4
Electric	928	32,369					5
							6
Electric	928	31,755					7
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		295,634					46

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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:

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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 INTERNALLY	
3		
4	A(1)B GENERATION: FOSSIL-FUEL STEAM	SNCR DEMONSTRATION ON CARDINAL 1
5		5 ITEMS UNDER $5,000
6		
7	A(1)D GENERATION: NUCLEAR	1 ITEM UNDER $5,000
8		
9	A(1)E GENERATION: UNCONVENTIONAL	1 ITEM UNDER $5,000
10		
11	A(2) SYSTEM PLANNING, ENGINEERING & OPERATION	POWER QUALITY INSTRUMENTATION LABORATORY DEVELOPMENT
12		3 ITEMS UNDER $5,000
13		
14	A(3)A TRANSMISSION: OVERHEAD	VOLTAGE SECURITY MONITORING & CONTROL (VSMAC)
15		6 ITEMS UNDER $5,000
16		
17	A(3)B TRANSMISSION: UNDERGROUND	3 ITEMS UNDER $5,000
18		
19	A(4) DISTRIBUTION:	6 ITEMS UNDER $5,000
20		
21	A(5) ENVIRONMENT: (OTHER THAN EQUIPMENT)	AMMONIA CONDITIONING OF FLUE GAS
22		OHIO RIVER ECOLOGICAL RESEARCH PROGRAM
23		4 ITEMS UNDER $5,000
24		
25	A(6) OTHER:	10 ITEMS UNDER $5,000
26		
27	A(7) TOTAL COST INCURRED INTERNALLY	
28		
29	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
30	DEMONSTRATION PERFORMED EXTERNALLY	
31		
32	B(1) RESEARCH SUPPORT TO THE ERC OR THE EPRI:	3 ITEMS UNDER $5,000
33		BIG SANDY BOILER PREDICTIVE MAINTENANCE PROJECT
34		
35	B(2) RESEARCH SUPPORT TO EDISON ELECTRIC INST.	NATIONAL EMF RESEARCH PROGRAM
36		
37	B(5) TOTAL COSTS INCURRED EXTERNALLY	
38		

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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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
38,467		506	38,467		4
7,110		506/566	7,110		5
					6
3,634		930	3,634		7
					8
537		930	537		9
					10
11,481		930	11,481		11
5,377		566/930	5,377		12
					13
8,253		566	8,253		14
7,498		506/566	7,498		15
					16
1,300		566/588	1,300		17
					18
5,320		566/588	5,320		19
					20
79,121		506	79,121		21
9,959		506	9,959		22
3,903		506/930	3,903		23
					24
13,501		506/588	13,501		25
					26
195,461			195,461		27
					28
					29
					30
					31
	1,433	500/506	1,433		32
	40,000	512	40,000		33
					34
	5,426	566	5,426		35
					36
	46,859		46,859		37
					38

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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	4,278,404		
4	Transmission	613,793		
5	Distribution	3,737,968		
6	Customer Accounts	3,854,335		
7	Customer Service and Informational	661,406		
8	Sales	43,055		
9	Administrative and General	1,804,559		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	14,993,520		
11	Maintenance			
12	Production	3,070,580		
13	Transmission	568,998		
14	Distribution	3,244,545		
15	Administrative and General	592,190		
16	TOTAL Maint. (Total of lines 12 thru 15)	7,476,313		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	7,348,984		
19	Transmission (Enter Total of lines 4 and 13)	1,182,791		
20	Distribution (Enter Total of lines 5 and 14)	6,982,513		
21	Customer Accounts (Transcribe from line 6)	3,854,335		
22	Customer Service and Informational (Transcribe from line 7)	661,406		
23	Sales (Transcribe from line 8)	43,055		
24	Administrative and General (Enter Total of lines 9 and 15)	2,396,749		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	22,469,833		22,469,833
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)			

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	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		5,275,047	5,275,047
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	22,469,833	5,275,047	27,744,880
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	7,034,741	1,093,050	8,127,791
66	Gas Plant			
67	Other			
68	TOTAL Construction (Total of lines 65 thru 67)	7,034,741	1,093,050	8,127,791
69	Plant Removal (By Utility Departments)			
70	Electric Plant	670,253	23,107	693,360
71	Gas Plant			
72	Other			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	670,253	23,107	693,360
74	Other Accounts (Specify):			
75	Fuel Stock Expenses - Undistributed	756,512	-720,523	35,989
76	Stores Expense - Undistributed - T&D Expense	1,168,688	-1,168,688	
77	Transportation Expenses - Maintenance	339,799	-339,799	
78	Transportation Expenses - Accidents	506	-506	
79	Transportation Expenses - O&M - General and OH	162,051	-162,051	
80	Building Service - Clearing	82,961	-82,961	
81	MDD - Other Work In Progress	1,919,932	-1,919,932	
82	Expenditures to CNIC, Political, & R/A	82,016		82,016
83	Non-Productive Payroll	2,050,362	-1,996,744	53,618
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,562,827	-6,391,204	171,623
96	TOTAL SALARIES AND WAGES	36,737,654		36,737,654

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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	7,891,480
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)	7,891,480
10	Purchases	3,899,973
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	1,723,922
17	Delivered	1,723,922
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)	11,791,453

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,491,942
23	Requirements Sales for Resale (See instruction 4, page 311.)	80,526
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,802,751
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	416,234
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	11,791,453

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MONTHLY PEAKS AND OUTPUT

1. 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 in column (b) the system's energy output for each month such that the total on Line 41 matches the total on Line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on Line 24. include in the monthly amounts any energy losses associated with the sales so that the total on Line 41 exceeds the amount on Line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt Load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c)
5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	986,762	328,894	1,207	20	9
30	February	985,706	409,091	1,095	25	9
31	March	1,025,529	419,085	1,299	13	8
32	April	907,597	396,387	987	6	7
33	May	814,951	276,831	1,077	20	16
34	June	1,003,353	454,969	1,120	22	15
35	July	999,137	399,466	1,178	21	16
36	August	995,304	381,994	1,213	25	16
37	September	1,142,927	588,544	1,114	14	16
38	October	964,624	429,575	1,043	23	8
39	November	900,252	321,971	1,093	23	9
40	December	1,066,421	395,944	1,250	30	10
41	TOTAL	11,792,563	4,802,751			

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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 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 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	Neat Peak Demand on Plant - MW (60 minutes)	1104	0
7	Plant Hours Connected to Load	8760	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1060	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	177	0
12	Net Generation, Exclusive of Plant Use - KWh	7891480000	0
13	Cost of Plant: Land and Land Rights	1076545	0
14	Structures and Improvements	29075673	0
15	Equipment Costs	228248479	0
16	Total Cost	258400697	0
17	Cost per KW of Installed Capacity (line 5)	235.5951	0.0000
18	Production Expenses: Oper, Supv, & Engr	1955621	0
19	Fuel	83751336	0
20	Coolants and Water (Nuclear Plants Only)	0	0
21	Steam Expenses	2405561	0
22	Steam From Other Sources	0	0
23	Steam Transferred (Cr)	0	0
24	Electric Expenses	249461	0
25	Misc Steam (or Nuclear) Power Expenses	4242518	0
26	Rents	8655	0
27	Allowances	0	0
28	Maintenance Supervision and Engineering	1706432	0
29	Maintenance of Structures	740954	0
30	Maintenance of Boiler (or reactor) Plant	6733093	0
31	Maintenance of Electric Plant	1432290	0
32	Maintenance of Misc Steam (or Nuclear) Plant	1217879	0
33	Total Production Expenses	104443800	0
34	Expenses per Net KWh	0.0132	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
37	Quantity (units) of Fuel Burned	3039586	18880	0	0	0	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12225	139172	0	0	0	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	27.298	20.117	0.000	0.000	0.000	0.000
40	Average Cost of Fuel per Unit Burned	27.418	21.763	0.000	0.000	0.000	0.000
41	Average Cost of Fuel Burned per Million BTU	1.121	4.732	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per KWh Net Gen	0.011	0.000	0.000	0.000	0.000	0.000
43	Average BTU per KWh Net Generation	9444.000	0.000	0.000	0.000	0.000	0.000

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FOOTNOTE DATA

Page Number (a)	Item (row) Number (b)	Column Number (c)
402	35	

Used for Start-up, banking of boiler, flame stabilization, and supplemental firing

Page Number (a)	Item (row) Number (b)	Column Number (c)
402	35	

Footnote Linked. See note on 402, Row: 35, col/item:

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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)	Structure (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	0701 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	0104 MILLBROOK, OH	SILOAM, KY	69.00	138.00	ST	1.58		1
18	0104 MILLBROOK, OH	SILOAM, KY	69.00	138.00	WP	0.09		1
19	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	1.47		1
20	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	WP	16.92	16.92	1
21	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	ST	0.64		2
22	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	ALUMT	32.43		1
23	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	10.05		1
24	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	16.41	0.33	1
25	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	ST	0.71	14.41	1
26	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	WP	0.38		1
27	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	WP	7.90		1
28	0115 CHADWICK	COALTON	138.00	138.00	WP	0.98		1
29	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	WP	5.08	1.58	1
30	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	WP	26.40		1
31	0118 DEWEY	MASSEY	69.00	138.00	ST	3.09		1
32	0119 BESLEY LAYNE	ALLEN	46.00	138.00	WP	6.35		1
33	0120 HATFIELD	SPRIGG	138.00	138.00	WP	5.88		1
34	0121 HATFIELD	INEZ	138.00	138.00	WP	14.67		1
35	0122 INEZ	LOVELY	138.00	138.00	WP	6.86		1
36					TOTAL	1,197.46	40.27	46

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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 MCMA	258	10,045	10,303					1
954 MCMA	554,508	5,276,357	5,830,865					2
								3
954 MCMA	2,843,090	14,691,137	17,534,227					4
								5
								6
351.5 VAR	16,997,648	102,812,450	119,810,098					7
954 MCMA	177,562	1,019,199	1,196,761					8
500 MCMCU	197,622	1,758,181	1,955,803					9
								10
556.5 VAR	492,653	1,311,181	1,803,834					11
								12
1033.5 VAR	8,672	63,923	72,595					13
397.5 MA	4,478	121,822	126,300					14
397.5 MCMCU	59,507	477,449	536,956					15
								16
556 MCMA	8,176	111,403	119,579					17
								18
636 MCMA	84,068	1,261,746	1,345,814					19
								20
397 MCMA	2,128	444,269	446,397					21
397.5 MCMA	519,478	2,471,115	2,990,593					22
								23
								24
795 MCMA	16,110	297,567	313,677					25
								26
795 MCMA	6,858	355,978	362,836					27
795 MCMA	337,532	422,416	759,948					28
556.5 MCM	394,836	1	394,837					29
795 MCMA	555,042	408,336	963,378					30
336.4 MCMA	16,653	445,559	462,212					31
	141,505	1,132,585	1,274,090					32
1033 MCM		1,506,763	1,506,763					33
10335 VAR	459,705	3,932,737	4,392,442					34
10335 VAR	2,783	314,627	317,410					35
	28,021,847	186,797,588	214,819,435	23,845	1,153,100		1,176,945	36

Attachment

KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0126 INEZ	MARTIKI	138.00	138.00	WP	0.33		1
2	0127 BIG SANDY	INEZ	138.00	138.00	ST	23.00		1
3	0106 DORTON	FLEMING	138.00	138.00	WP	7.64		1
4	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60		1
5	0112 MASSEY	LOVELY	69.00	138.00	WP	4.34		1
6	0114 LOVELY	MCCLURE	69.00	138.00	WP	6.96		1
7	0123 ENGLE TAP		69.00	138.00	WP	4.60		
8	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01		1
9	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
10	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22		2
11	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00		1
12								
13								
14								
15	9069 69KV LINES AND		69.00	69.00		589.56	5.93	
16								
17								
18	765KV EXPENSES							
19								
20	345KV EXPENSES							
21								
22	161KV EXPENSES							
23								
24	138KV EXPENSES							
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,197.46	40.27	46

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
10335 VAR	2,269	56,174	58,443					1
795 MCMA	1,065,514	11,506,041	12,571,555					2
795 MCMA	217,206	1,174,346	1,391,552					3
397 MCMA	118,238	1,268,638	1,386,876					4
795 MCMA	40,398	292,027	332,425					5
795 MCMA	121,009	451,593	572,602					6
10335 VAR	120,301	1,249,768	1,370,069					7
10335 VAR		97,436	97,436					8
	51,485		51,485					9
795 ACSR	1,393	225,286	226,679					10
1351 KCM	650	1,179,194	1,179,844					11
								12
								13
								14
	2,402,512	28,650,239	31,052,751	11,740	567,720		579,460	15
								16
								17
				5,134	248,260		253,394	18
								19
				166	8,050		8,216	20
								21
				923	44,623		45,546	22
								23
				5,882	284,447		290,329	24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	28,021,847	186,797,588	214,819,435	23,845	1,153,100		1,176,945	36

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Name of Respondent	This Report Is:	Date of Report	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/30/1999	Dec. 31, 1998

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 From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STURCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STURCTURE Present (f)	Ultimate (g)
1	BIG SANDY	INEZ	23.00	STEEL		1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		23.00			1	1

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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 KV (Operating) (k)	LINE COST				Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	
795 MCM			138	1,065,514	6,673,504	4,832,537	12,571,555	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
				1,065,514	6,673,504	4,832,537	12,571,555	44

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	46.00	4.00	
8		T-U	46.00	2.00	
9	ELKHORN CITY-ELKHORN CITY	D-U	69.00	12.00	
10		T-U	69.00	46.00	
11	ELKWOOD-VIRGIE	T-U	46.00	34.00	
12	ENGLE-ENGLE	D-U	69.00	34.00	
13	FALCON-SALYERSVILLE	T-U	69.00	46.00	
14		T-U	69.00	12.00	
15	FEDS CREEK-NIGH	D-U	69.00	12.00	
16	FLEMING-FLEMING	T-U	138.00	69.00	46.00
17		T-U	69.00	12.00	
18	FORDS BRANCH-SHELBIANA	D-U	46.00	34.00	12.00
19	FORTY-SEVENTH ST.-ASHLAND	D-U	69.00	12.00	
20	FREMONT	D-U	138.00	69.00	7.00
21		D-U	138.00	12.00	
22	GARRETT-GARRETT	D-U	46.00	34.00	
23		D-U	34.00	12.00	
24	GRAYSON	D-U	69.00	12.00	
25	HADDIX-HADDIX	D-U	69.00	34.00	
26	HATFIELD-SO. WILLIAMSON	T-U	138.00	69.00	46.00
27		T-U	46.00	7.00	
28	HAZARD-LOTHAIR	T-U	138.00	69.00	12.00
29		T-U	161.00	138.00	11.00
30		T-U	138.00	34.00	
31		T-U	69.00	34.00	
32		T-U	34.00	12.00	
33	HAZARD	T-U	69.00	12.00	
34	HURLEY	D-U	69.00	12.00	
35	JENKINS-PIKEVILLE	D-U	69.00	12.00	
36	MAYKING-PIKEVILLE	D-U	69.00	13.00	
37	ASHLAND-ASHLAND	D-U	69.00	12.00	
38	BAKER-LOUISA	T-U	765.00	345.00	34.50
39	BAKER	T-U	345.00	138.00	34.50
40	BARRENSHE-FREEBURN	D-U	69.00	12.00	

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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) 04/30/1999	Year of Report Dec. 31, 1998

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.
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
2	1					7
1	1					8
8	1		STAT CAP	1	14	9
20	1					10
25	1		STAT CAP	1	11	11
20	1					12
20	1					13
20	1					14
12	1					15
130	1		STAT CAP	1	14	16
20	1					17
30	1					18
20	1					19
100	2					20
11	1					21
20	1					22
5	1					23
20	1					24
25	1					25
60	1					26
4	1					27
180	2		STAT CAP	2	46	28
135	3	1				29
60	2					30
		1				31
4	1	1				32
		1				33
22	1					34
11	1					35
20	1					36
20	1		STAT CAP	1	16	37
2302	9		REACTOR	3	300	38
672	1					39
15	1					40

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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	BEAVER CREEK-CLEAR CR. JCT.	T-U	138.00	69.00	46.00
2		T-U	138.00	46.00	12.00
3		T-U	69.00	12.00	
4		T-U	46.00		
5		T-U	12.00		
6		T-U	138.00	8.00	
7	BECKHAM-HINDMAN	D-U	138.00	34.00	
8	BEEFHIDE-JENKINS	D-U	138.00	34.50	
9	BELHAVEN-FLATWOODS	D-U	138.00	12.00	
10	BELLEFONTE-BELLEFONTE	T-U	138.00	34.50	
11		T-U	138.00	69.00	34.50
12	BELLEFONTE-BELLEFONTE	T-U	138.00	69.00	34.50
13		T-U	138.00	12.00	
14	BETSY LAYNE-BETSY LAYNE	T-U	46.00	12.00	
15		T-U	46.00	2.00	
16		T-U	138.00	69.00	46.00
17		T-U	138.00	34.00	
18	BIG SANDY-LOUISA	T-A	138.00	34.50	
19		T-A	22.00	4.00	
20		T-A	345.00	24.50	
21		T-A	138.00	23.00	
22		T-A	138.00	69.00	34.50
23		T-A	138.00	34.00	12.00
24					
25			138.00	4.16	
26	BONNYMAN-BONNYMAN	T-U	69.00	34.00	
27	BUSSEYVILLE-BUSSEYVILLE	D-U	138.00	34.50	
28	CANNONSBURG-ASHLAND	D-U	69.00	34.50	
29	CEDAR CREEK-PIKEVILLE	T-U	138.00	69.00	46.00
30	CEDAR CREEK	T-U	46.00		
31		T-U	35.00	12.00	
32		T-U	35.00	7.00	
33	CHADWICK-CHADWICKS CREEK	T-U	138.00	69.00	34.50
34	CLINTWOOD	D-U	69.00	12.00	
35	COALTON-COALTON	D-U	69.00	12.00	
36	HENRY CLAY-HELLIER	D-U	46.00	35.00	
37	HITCHINS-HITCHINS	D-U	69.00	12.00	
38	HOWARD COLLINS-ASHLAND	D-U	69.00	12.00	
39	INEZ-INEZ	D-U	138.00	69.00	
40	INEZ	D-U	13.00	37.00	14.00

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
30	1		STAT CAP	8	317	1
39	3	1	REACTOR	6	126	2
5	1					3
2	2	1				4
1	1					5
125	1	1				6
25	1					7
20	1					8
20	1					9
45	1					10
196	1					11
100	1					12
20	1					13
5	1		STAT CAP	1	10	14
2	1					15
30	1					16
25	1					17
20	2					18
98	5					19
950	1					20
300	2					21
90	1					22
8	1					23
						24
38	2					25
25	1					26
25	1					27
25	1					28
90	1					29
111	1					30
5		5				31
1		1				32
200	1					33
20	1					34
25	1		STAT CAP	1	14	35
30	1					36
10	2					37
31	2					38
50	1		STAT CAP	1	10	39
160	1					40

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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		D-U	138.00	37.00	
2		D-U	26.00		
3	JACKSON-JACKSON	T-U	69.00	12.00	
4	JEFF-PIKEVILLE	D-U	69.00	13.00	
5	JOHNS CREEK-KIMPER	T-U	138.00	69.00	34.00
6	KENWOOD-PAINTSVILLE	D-U	46.00	12.00	
7	KEYSER-KEYSER	D-U	69.00	12.00	
8	LESLIE-WOOTEN	T-U	161.00	69.00	12.00
9		T-U	69.00	34.00	12.00
10	LICK FORD	D-U	69.00	35.00	
11	LOUISA-LOUISA	D-U	35.00	12.00	
12	LOVELY-LOVELY	T-A	138.00	34.00	
13	OLIVE HILL-ASHLAND	D-U	69.00	12.00	
14		D-U	69.00	4.00	
15	OXYGEN PLANT	D-U	138.00	13.20	
16	PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
17	POUND	D-U	69.00	12.00	
18	PRINCESS-CANNONSBURG	D-U	69.00	69.00	
19	RUSSELL-RUSSELL	D-U	69.00	12.00	
20	SIDNEY-SIDNEY	D-U	69.00	12.00	
21	SLEMP-SLEMP	D-U	69.00	34.00	
22	SOUTH PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
23		D-U	35.00		
24		D-U	34.00	3.00	
25	STINNETT-HOSKINGSTON	D-U	161.00	34.00	7.00
26	STONE-BELFRY	T-U	138.00	69.00	46.00
27	TENTH STREET-ASHLAND	D-U	69.00	69.00	
28	THELMA-PAINTSVILLE	T-U	138.00	69.00	46.00
29		T-U	46.00	3.00	
30	TOM WATKINS	D-U	69.00	12.00	
31	VICCO-VICCO	D-U	138.00	35.00	
32	WEST PAINTSVILLE-PAINTSVILLE	D-U	69.00	12.00	
33	WHITESBURG-WHITESBURG	D-U	69.00	12.00	
34	WILLIAMSON-S. WILLIAMSON	D-U	46.00	12.00	
35		D-U	46.00	4.00	
36	WURTLAND-WURTLAND	D-U	69.00	12.00	
37					
38	45 STATIONS UNDER 10,000 KVA	T/D			
39					
40					

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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

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.
320	2					1
172	2					2
14	2		STAT CAP	1	5	3
11	1					4
90	1		STAT CAP	1	10	5
20	1					6
20	1					7
90	1					8
20	1					9
11	1					10
10	2					11
30	1					12
8	1					13
5	1					14
25	1					15
25	1					16
32	2					17
20	1					18
20	1					19
20	1					20
31	2					21
25	1					22
		1				23
		1				24
20	2	1				25
50	1					26
20	1					27
70	1		STAT CAP	2	40	28
3	3					29
16	2					30
30	1					31
12	1					32
16	2		STAT CAP	1	13	33
8	1					34
		1				35
20	1					36
						37
244	59					38
						39
						40

Attachment
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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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Item No. 3s

Line No.	Item (a)	Number of Watt-hour Meters (b)	LINE TRANSFORMERS Number (c)	Total capacity (in (MVa) (d)
1	Number at Beginning of Year	176,849	87,756	2,741
2	Additions During Year			
3	Purchases	6,973	2,517	64
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	6,973	2,517	64
6	Reductions During Year			
7	Retirements	6,595	1,336	32
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	6,595	1,336	32
10	Number at End of Year (Lines 1 + 5 - 9)	177,227	88,937	2,773
11	In Stock	3,883	764	64
12	Locked Meters on Customers' Premises	3,951		
13	Inactive Transformers on System			
14	In Customers' Use	169,306	88,015	2,705
15	In Company's Use	87	158	4
16	TOTAL End of Year (Total 11 to 15. This should equal line 10)	177,227	88,937	2,773

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, Liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.
2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgment where direct comparisons are not available. Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations. Examples of these costs would include a portion of the costs of tall smokestacks, underground Lines, and landscaped substations. Explain such costs in a footnote.
3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimations on a percentage of plant basis. Explain such estimations in a footnote.
4. Report all costs under the major classifications provided below and include, as a minimum, the items Listed-hereunder:

A. Air pollution control facilities:
(1) Scrubbers, precipitators, tall smokestacks, etc.
(2) Changes necessary to accommodate use of environmentally clean fuels such as Low ash or low sulfur fuels including storage and handling equipment
(3) Monitoring equipment
(4) Other.

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc.
(2) Waste water treatment equipment
(3) Sanitary waste disposal equipment
(4) Oil interceptors
(5) Sediment control facilities
(6) Monitoring equipment
(7) Other.

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment
(2) Land
(3) Settling ponds
(4) Other.

D. Noise abatement equipment:
(1) Structures
(2) mufflers
(3) Sound proofing equipment
(4) Monitoring equipment
(5) Other.

E. Esthetic costs:
(1) Architectural costs
(2) Towers
(3) Underground lines
(4) Landscaping
(5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
(1) Preparation of environmental reports
(2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
(3) Parks and related facilities
(4) Other.

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5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).
6. Report construction work in progress relating to environmental facilities at Line 9.

Line No.	Classification of Cost	CHANGES DURING YEAR			Balance at End of Year	Actual Cost
		Additions	Retirements	Adjustments		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Air Pollution Control Facilities	3,901,804	10,203		27,409,791	27,409,791
2	Water Pollution Control Facilities				3,798,756	3,798,756
3	Solid Waste Disposal Costs				5,567,791	5,567,791
4	Noise Abatement Equipment					
5	Esthetic Costs					
6	Additional Plant Capacity	100,282			2,260,910	
7	Miscellaneous (Identify significant)					
8	TOTAL (Total of lines 1 thru 7)	4,002,086	10,203		39,037,248	36,776,338
9	Construction Work in Progress				2,034,609	2,034,609

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/30/1999	Dec. 31, 1998

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on Page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.
2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.
3. Report expenses under the subheadings listed below.
4. Under Item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.
5. Under Item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.
6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under Item 8 licensing and similar fees on such facilities.
7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expenses (a)	Amount (b)	Actual Expenses (c)
1	Depreciation	1,475,608	1,390,146
2	Labor, Maint, Mtrls, & Supplies Cost Related to Env Fac & Programs	432,564	432,564
3	Fuel Related Costs		
4	Operation of Facilities	631,238	631,238
5	Fly Ash and Sulfur Sludge Removal	339,533	339,533
6	Difference in Cost of Environmentally Clean Fuels		
7	Replacement Power Costs	204,120	204,120
8	Taxes and Fees		
9	Administrative and General	73,883	73,883
10	Other (Identify significant)		
11	TOTAL	3,156,946	3,071,484

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KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3s

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Item No. 3s

CASE NUMBER:

99-149

KENTUCKY POWER COMPANY

d/b/a

AMERICAN ELECTRIC POWER

PSC CASE NO. 99-149

RESPONSE TO DATA REQUEST (2ND SET)

KENTUCKY PUBLIC SERVICE COMMISSION

DATED MAY 11, 1999

STITES & HARBISON

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May 17, 1999

Ms. Helen Helton
Executive Director
Public Service Commission of Kentucky
P.O. Box 615
Frankfort, KY 40602-0615

RE: In the Matter of Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and South West Corporation, P.S.C. Case No. 149

RECEIVED
MAY 17 1999
PUBLIC SERVICE COMMISSION

Dear Ms. Helton:

Please accept for filing the original and 12 copies of the Responses of Kentucky Power Company, American Electric Power Company, Inc. and Central and South West Corporation (the "Joint Applicants) to the Commission's Information Request dated May 11, 1999. A copy has been provided to all parties of record in conformity with the certificate of service attached to the Responses.

Also, please accept for filing an original and seven copies of the Joint Applicants' Responses to the Information Requests of Kentucky Electric Steel, Inc. (Second Set) and Attorney General, Office of Rate Intervention (Second Set). A copy has been provided to all parties of record in conformity with the certificate of service attached to the Responses.

Thank you for your assistance in this matter.

Very truly yours,

Mark R. Overstreet

cc: William H. Jones, Jr
Elizabeth Blackford
James Brew
Richard S. Taylor
David F. Boehm

KE057:KE131:2147:FRANKFORT

RECEIVED
MAY 17 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

JOINT APPLICATION OF KENTUCKY	)	
POWER COMPANY, AMERICAN ELECTRIC	)	
POWER COMPANY, INC., AND CENTRAL	)	CASE NO. 99-149
AND SOUTH WEST CORPORATION	)	
REGARDING A PROPOSED MERGER	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

Filed May 17, 1999

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Joint Applicants' Response to Commission's Information Request dated May 11, 1999 was served by overnight delivery on this 14th day of May, 1999 upon:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

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Mark R. Overstreet

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	) CASE NO. 99-149

<u>O R D E R</u>

IT IS ORDERED that American Electric Power Company, Inc. ("AEP") shall file the original and 12 copies of the following information with the Commission no later than May 17, 1999, with a copy to all parties of record. Each copy of the data requested shall be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet shall be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been provided along with the original application, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. When applicable, the information requested herein should be provided for total company operations and jurisdictional operations, separately.

1. Refer to the response to the Commission's April 28, 1999 Order, Item 1. The question was seeking information concerning the potential exposure of Kentucky Power in the event a termination of the merger occurred. It is fully understood that these fees or payments will not be payable unless the merger is terminated pursuant to

Section 9.1 of the Merger Agreement. With this clarification, provide the originally requested information.

2. Refer to the response to the Commission's April 28, 1999 Order, Item 15. The response only answered part of the request. Under the Affiliate Standards contained in the Indiana Settlement, would market information be readily available to an affiliate engaged in activities other than exempt wholesale generation or power marketing, such as telecommunication services or home appliance repair? Explain.

3. Refer to the response to the Commission's April 28, 1999 Order, Item 33. AEP/Kentucky Power have committed to provide the annual performance measures by the end of May of the year following the calendar year in question.

a. Explain why it will take five months to provide this information.

b. In the jurisdictions where this information is already provided routinely, indicate by jurisdiction how promptly AEP must provide this information.

c. Indicate how promptly AEP and CSW have committed to providing this information in other jurisdictions.

4. Refer to the response to the Commission's April 28, 1999 Order, Item 20. The first sentence is not responsive to the original request. The testimony was clear that "no revenue enhancement opportunities were identified in this transaction." The request referred to Mr. Flaherty's example of increased off-system sales as a revenue enhancement opportunity. The request asked for an <u>explanation</u> of why the combination of AEP and CSW would <u>not create</u> a greater level of such revenue enhancement opportunities than the two systems could expect operating independently of each other. Please provide the explanation sought by the original request.

5. Refer to the response to the Commission' April 28, 1999 Order, Item 22. It is proposed that the estimated "Net Production-Related Savings" of $98 million arising from the merger be allocated on a 50/50 basis between AEP and CSW (as shown in Mr. Munczinski's Exhibit REM-4, $49 million would be allocated to each company). Mr. Baker's Exhibit JCB-2 shows that the Net Production-Related Savings were calculated by taking the estimated $198 million in Production-Related Savings, less the estimated $39 million in Transmission Costs, less the estimated $61 million in Foregone Net Revenues, to arrive at $98 million in Net Production-Related Savings. As indicated in part (a) of the above-referenced response, the power flows over the 250 MW transmission path are projected to be predominately from the East Zone to the West Zone. Also in part a. of the response Mr. Baker indicates that the $61 million in Foregone Net Revenues is an estimation of the amount that the East Zone (AEP) would not be receiving as a result of sales to the West Zone (CSW). Therefore, the Production-Related Savings occur due to AEP's coal-fired generation displacing CSW's higher priced gas-fired generation. In addition, the Foregone Net Revenues will be AEP's foregone revenues by virtue of its sales to CSW (presumably, the Transmission Costs would be costs borne by CSW as the party on the receiving end of these transactions). Given these circumstances, with the benefits being created by AEP and with AEP experiencing the greater amount of costs, i.e. lost revenues, explain why the 50/50 sharing is reasonable from the perspective of AEP.

6. Refer to the response to the Commission's April 28, 1999 Order, Item 24. Therein, Mr. Bailey delineates several measures already in place or planned for the future to improve system reliability in the Kentucky Power service area. Mr.

Bailey's direct testimony and exhibits identify the three primary measures used by AEP to monitor its service reliability and the three primary measures used to monitor the performance of its call centers. Is AEP willing to file with the Commission quarterly reports of these service reliability and performance measures?

Done at Frankfort, Kentucky, this 11th day of May, 1999.

By the Commission

ATTEST:

Executive Director

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission's April 28, 1999 Order, Item 1. The question was seeking information concerning the potential exposure of Kentucky Power in the event a termination of the merger occurred. It is fully understood that these fees or payments will not be payable unless the merger is terminated pursuant to Section 9.1 of the Merger Agreement. With this clarification, provide the originally requested information.

RESPONSE:

If the proposed merger is terminated and the referenced payments are made by AEP, it is expected that such fees and expenses will be paid by the parent company and only allocated by the parent to, among others, Kentucky Power Company if they are recoverable from ratepayers.

WITNESS: RICHARD E. MUNCZINSKI

2

KPSC Case No. 99-149
Staff's (2nd Set)
Order Dated May 11, 1999
Supplemental Request for Information
Item No. 2
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission's April 28, 1999 Order, Item 15. The response only answered part of the request. Under the Affiliate Standards contained in the Indiana Settlement, would market information be readily available to an affiliate engaged in activities other than exempt wholesale generation or power marketing, such as telecommunication services or home appliance repair? Explain.

RESPONSE:

No market information (i.e., customer names and consumption information) is supplied to any affiliate without the written consent of the customer specifying the information to be released.

WITNESS: RICHARD E. MUNCZINSKI

3

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission's April 28, 1999 Order, Item 33. AEP/Kentucky Power have committed to provide the annual performance measures by the end of May of the year following the calendar year in question.

a. Explain why it will take five months to provide this information.

b. In the jurisdictions where this information is already provided routinely, indicate by jurisdiction how promptly AEP must provide this information.

c. Indicate how promptly AEP and CSW have committed to providing this information in other jurisdictions.

RESPONSE:

a. The end of May timeframe was suggested to give company personnel sufficient time to receive all the needed input data/information from either our field organizations or our suppliers (in the case of "call blockage" information) and allow them adequate time to verify, process and analyze the data to develop the necessary reports for the Commission given other year end workload reporting requirements. The next couple of paragraphs describe some of the detail involved in pulling together the reliability information. A similar process is involved in compiling the Call Center information. In addition, this timeframe is consistent with the timeframes for providing similar information in other AEP jurisdictions.

The AEP "Distribution Outage Reporting" (DOR) system consists of various procedures and a form called the "Trouble Damage and Interruption Report" or "TDIR". To achieve accurate reporting, the minimum time required to verify and process reports in the system is six weeks after the last day of the reporting month. One reason for this is our on-line validation process at the point of data entry. This

WITNESS: MARK A. BAILEY

RESPONSE CONTINUED:

validation procedure involves filing all records having an outage duration in excess of 6 hours or involving an operation of a station breaker in an "Un-Approved TDIR Report" file. Region Coordinators are assigned to review and approve the reports in this file on a weekly basis to verify that the data is correct. If any data is questionable, the coordinator will return the TDIR entry back to the point of origin for verification and /or corrections. This procedure may take another 2 weeks due to various reasons (i.e. vacations, shift change in work schedules of field personnel, etc.). Another reason for the required time is what is known as the TDIR "Deferred File". This allows the data entry person to defer a TDIR report if information contained in it is incomplete. A deferred report may be held until the time when all missing data is collected and entered into the system.

Major storms can result in additional time requirements to collect, sort and send all the hard copy reports to the appropriate areas for data entry. After all data entry is completed, verified and approved for the month, another validation report is performed on all the data to assure that the correct weather conditions (major storm, if applicable) coding was entered correctly. Again, if data is incorrect, revisions will have to be made and the process starts over. Although this validation process may appear to be time consuming, our goal is to compile the most accurate and complete outage data possible to allow us to identify areas where improvement(s) can be made.

b. The following is a summary by state jurisdiction for the AEP service territory.

Indiana - This type of information has not been regularly provided to the Commission in the past. The recent merger settlement agreement in Cause No. 41210 specified that the information will be provided by the end of May in the year following the year in question.

Michigan - Information which could be used to derive the CAIDI and SAIFI indices has been reported informally to the Commission's Engineering Division for several years. No specific timeframe to provide the information has been specified. The last two years reports were dated April 9, 1999 and April 21, 1998, respectively.

WITNESS: MARK A. BAILEY

RESPONSE CONTINUED:

Ohio - The Commission has adopted a state-wide requirement for all electric utilities to report reliability information by May 1st of the following year for the year in question.

West Virginia - There is no formal requirement to provide this type of information. Previously, we provided a member of the Commission staff with reliability data. The last report sent provided 1997 information. Although we have no record of the actual date this information was provided, AEP regulatory personnel based in West Virginia believe it was in the April/May timeframe.

Virginia - As part of the company's last rate case stipulation which is scheduled to expire on December 31, 2000, we agreed to provide reliability information. There was no explicit timeframe spelled out in the stipulation for reporting this information. We provided our first report covering 1998 performance in April of this year.

Tennessee - This information is not being provided to the Commission.

c. The following summary lists AEP and CSW's commitments for reporting this information in the CSW states.

Arkansas - Under the terms of the merger settlement, AEP and CSW agreed to provide reliability information by the end of May in the year following the year in question.

Oklahoma - Under the terms of the merger settlement, AEP and CSW agreed to provide reliability information by the end of May in the year following the year in question.

Louisiana - The Commission has adopted a statewide requirement for all electric utilities to report reliability information by April 1st of the year following the year in question.

Texas - The Commission has adopted a state-wide requirement for all electric utilities to report reliability information within 45 days after the end of the period being reported.

WITNESS: MARK A. BAILEY

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission's April 28, 1999 Order, Item 20. The first sentence is not responsive tot he original request. The testimony was clear that "no revenue enhancement opportunities were identified in this transaction." The request referred to Mr. Flaherty's example of increased off-system sales as a revenue enhancement opportunity. The request asked for an explanation of why the combination of AEP and CSW would not create a greater level of such revenue enhancement opportunities than the two systems could expect operating independently of each other. Please provide the explanation sought by the original request.

RESPONSE:

Applicants believe that there are opportunities to integrate CSW's generation merchant function with AEP's existing generation merchant function to seek additional off-system sales. Seeking additional off-system sales will require additional resources. At this time, Applicants have not prepared an estimate of post-merger off-system sales or a quantification of the cost of the additional resources required.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission' April 28, 1999 Order, Item 22. It is proposed that the estimated "Net Production-Related Savings" of $98 million arising from the merger be allocated on a 50/50 basis between AEP and CSW (as shown in Mr. Munczinski's Exhibit REM-4. $49 million would be allocated to each company). Mr. Baker's Exhibit JCB-2 shows that the Net Production-Related Savings were calculated by taking the estimated $198 million in Production-Related Savings, less the estimated $39 million in Transmission Costs, less the estimated $61 million in Foregone Net Revenues, to arrive at $98 million in Net Production-Related Savings. As indicated in part (a) of the above-referenced response, the power flows over the 250 MW transmission path are projected to be predominately from the East Zone to the West Zone. Also in part a. of the response Mr. Baker indicates that the $61 million in Foregone Net Revenues is an estimation of the amount that the East Zone (AEP) would not be receiving as a result of sales to the West Zone (CSW). Therefore, the Production-Related Savings occur due to AEP's coal-fired generation displacing CSW's higher priced gas-fired generation. In addition, the Foregone Net Revenues will be AEP's foregone revenues by virtue of its sales to CSW (presumably, the Transmission Costs would be costs borne by CSW as the party on the receiving end of these transactions). Give these circumstances, with the benefits being created by AEP and with AEP experiencing the greater amount of costs, i.e. lost revenues, explain why the 50/50 sharing is reasonable from the perspective of AEP.

RESPONSE:

With regard to the Transmission Costs, the cost of the firm transmission is a sunk cost which is allocated equally to each of the Zones in accordance with Service Schedule B, Section B2 of the System Transmission Integration Agreement "...the charges paid to third parties for firm transmission capacity to link the two zones and any revenues from the resale of transmission rights acquired in order to link the two zones shall be allocated equally between the AEP East Zone and the AEP West Zone. Allocation of such revenues within each zone shall be done on the same basis as before the Merger."

WITNESS: J. CRAIG BAKER

RESPONSE CONTINUED:

In the pricing of System Energy Exchanges under the System Integration Agreement (SIA), margins associated with foregone sales opportunities will be included in determining the selling zone's out of pocket cost in accordance with Service Schedule C and Section 1.31 of the SIA. Discussion and examples of the pricing of System Energy Exchanges are included in J. Craig Baker's Direct Testimony on pages 12 and 13.

As indicated in Exhibit JCB-2, the merger results in $198 million of production cost savings. In order to achieve those production cost savings, 250 MW of firm transmission service is required. Thus, the $39 million associated with firm transmission is necessary to achieve those savings; the Applicants believe it is reasonable to split that cost 50/50. As indicated in Service Schedule C and the discussion on pages 12 and 13 of J. Craig Baker's testimony, the selling zone will be compensated for its foregone sales opportunities. Hence, as a result of the merger, AEP will be benefiting from $49 million of net production-related savings that it would not otherwise have achieved.

In conclusion, the Applicants believe the split savings methodology is consistent with the Applicants' goal to share the benefits over and above what would have been achieved as independent systems.

WITNESS: J. CRAIG BAKER

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KPSC Case No. 99-149
Staff's (2nd Set)
Order Dated May 11, 1999
Supplemental Request for Information
Item No. 6
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Refer to the response to the Commission's April 28, 1999 Order, Item 24. Therein, Mr. Bailey delineates several measures already in place or planned for the future to improve system reliability in the Kentucky Power service area. Mr. Bailey's direct testimony and exhibits identify the three primary measures used by AEP to monitor its service reliability and the three primary measures used to monitor the performance of its call centers. Is AEP willing to file with the Commission quarterly reports of these service reliability and performance measures?

RESPONSE:

AEP/Kentucky Power could provide the specified service reliability and performance measure information quarterly. However providing the information on an annual basis may achieve the same result in a more effective manner. While we generally monitor our performance in key areas on a more frequent basis, we typically evaluate performance trends over a period longer than three months (due in large part to the fact that system conditions generally will not change in such a short timeframe and due to the effect that storms can have on results) before concluding that action which would require a significant change in process or the commitment of substantial financial resources needs to be taken. A year is more typical of the timeframe used to evaluate results. This timeframe also coincides with our fiscal and business planning cycles

WITNESS: MARK A. BAILEY

KENTUCKY POWER COMPANY

d/b/a

AMERICAN ELECTRIC POWER

PSC CASE NO. 99-149

RESPONSE TO DATA REQUEST (2ND SET)

KENTUCKY ELECTRIC STEEL, INC.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)))))	CASE NO. 99-149

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

Filed May 17, 1999

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Joint Applicants' Response to Second Set of Interrogatories and Requests for Production of Documents Propounded by Kentucky Electric Steel, Inc. to American Electric Power Company, Inc. was served by overnight delivery on this 14th day of May, 1999 upon:

Elizabeth E. Blackford
Assistant Attorney General
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1024 Capital Center Drive
Frankfort, Kentucky 40601

David F. Boehm
Boehm, Kurtz & Lowry
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36 East Seventh Street
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315 High Street
Frankfort, Kentucky 40601

Mark R. Overstreet

BRICKFIELD

BURCHETTE

RITTS, P.C.

WASHINGTON, D.C.
AUSTIN, TEXAS

May 11, 1999

<u>VIA FACSIMILE AND MAIL</u>

Mark R. Overstreet, Esq.
Stites & Harbison
421 West Main Street
Frankfort, KY 40602

Re: <u>P.S.C. Case No. 99-149</u>

Dear Mr. Overstreet:

Pursuant to the Commission's Procedural Order, enclosed please find the *Supplemental Information Requests of Kentucky Electric Steel, Inc. to American Electric Power Company, Inc.* Please consider the instructions provided with Kentucky Electric Steel, Inc.'s first set of interrogatories to be applicable. Again, given the shortness of time, if you have any questions regarding these requests please call immediately.

Very truly yours,

BRICKFIELD, BURCHETTE & RITTS, P.C.

James W. Brew\cpa

James W. Brew

Enclosure

1025 THOMAS JEFFERSON STREET, N.W. EIGHTH FLOOR, WEST TOWER WASHINGTON, D.C. 20007 TELEPHONE 202-342-0800

SUPPLEMENTAL INFORMATION REQUESTS
OF
KENTUCKY ELECTRIC STEEL, INC.
TO
AMERICAN ELECTRIC POWER COMPANY, INC.

Case No. 99-149

KESI-15 Please state the date the last base rate case was filed of each AEP operating company and CSW member system. For each case, please provide:

a. the Docket or case number

b. the overall increase/decrease requested in terms of dollars and a percentage

c. the overall increase/decrease authorized in terms of dollars and a percentage

d. a statement indicating if the case was resolved by a settlement agreement

KESI-16 For the years 1999, 2000, and 2001, please provide:

a. AEP's forecasted revenues for transmission services provided to third parties

b. AEP's forecasted total and net revenues from wholesale sales to third parties

c. AEP's forecasted revenues from other sources (please identify) that will be credited to revenues of the operating companies

KESI-17 For the years 1995, 1996, 1997, 1998 and 1999 to date, for Kentucky Power Company please:

a. provide the Moody's and S&P credit rating

b. list each credit rating upgrade, grade affirmation or downgrade and provide the reasons given by the rating agency for each

c. the current credit rating assigned to the Company by Moody's and S&P

d. the criteria employed by Moody's and S&P in establishing the current credit rating

e. provide copies of any credit alerts issued by Moody's or S&P

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Supplemental Information Requests Of Kentucky Electric Steel, Inc. To American Electric Power Company, Inc.* was served via facsimile and First Class U.S. Mail, postage prepaid, this 11th day of May, 1999 on the following:

Mark R. Overstreet, Esq.
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James W. Brew / cpa
James W. Brew

15

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Please state the date the last base rate case was filed of each AEP operating company and CSW member system. For each case, please provide:

a. the Docket or case number

b. the overall increase/decrease requested in terms of dollars and a percentage

c. the overall increase/decrease authorized in terms of dollars and a percentage

d. a statement indicating if the case was resolved by a settlement agreement

RESPONSE:

Please see the attached schedule for the requested information.

WITNESS: RICHARD E. MUNCZINSKI

	Response to AG-2-7 / Response to AG-2-1 Re:CSW/I&M	Response to KESI-15					
	Last General Rate Case Date Filed	General Rate Docket or Case Number Part A	Overall Increase/Decrease Requested in Dollars Part B	Overall Increase/Decrease Requested In % Part B	Overall Increase/Decrease Authorized in Dollars Part C	Overall Increase/Decrease Authorized In % Part C	Was Case Settled?
AEP System Operating Companies							
Appalachian Power Company - WVA	5/12/99	99-0409-E-GI *	$50.3M Increase	8.4%	N/A	N/A	In Process
Columbus Southern Power Company	4/2/91	91-418-EL-AIR	$202.5M Increase	28.4%	$124.6M Increase	15.93%	No
Kentucky Power Company	3/27/91	91-066	$3.3M Decrease	-1.33%	$11.5M Decrease	-4.10%	Yes
Indiana Michigan Power Company-IN	4/27/92	IURC39314	$44.7M Increase	7%	$34.6M Increase	5.4%	No
Kingsport Power Company	5/26/92	92-04425	$5.5M Increase	6.6%	$4.6M Increase	5.6%	Yes
Ohio Power Company	7/6/94	94-996-EL-AIR	$152.4M Increase	10.33%	$66M Increase	5.8%	Yes
Wheeling Power Company	5/10/95	95-086	$4.5M Increase	5.55%	$0.0M Increase	0%	Yes

* Filing includes base and fuel. Information provided pertains to base only.

	Last General Rate Case Date Filed	General Rate Docket or Case Number Part A	Requested in Dollars Part B	Requested In % Part B	Authorized in Dollars Part C	Authorized In % Part C	Was Case Settled?
CSW Operating Companies							
Central Power and Light Company	Nov-95	14965	$71M Increase	8.49%	$21M Decrease	-3%	No
West Texas Utilities Company	Feb-95	13369	$1.1M Increase	0.40%	$13.5M Decrease	-7.4%	Yes
Southwestern Electric Power Company	Jan-99	U-23029	N/A	N/A	N/A	N/A	In Process
Public Service Company of Oklahoma	Nov-96	96-000-214	N/A	N/A	$35M Decrease	-5%	Yes

Note: The company only filed information for PSO and SWEPCo relating to its actual test year earnings and did not request an increase or decrease in its filings.
The SWEPCO docket is still in process.

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

For the years 1999, 2000, and 2001, please provide:

a. AEP's forecasted revenues for transmission services provided to third parties

b. AEP's forecasted total and net revenues from wholesale sales to third parties

c. AEP's forecasted revenues from other sources (please identify) that will be credited to revenues of the operating companies

RESPONSE:

a. AEP's forecasted revenues for transmission services provided to third parties are:

1999	$152.0 million
2000	$167.2 million
2001	$171.38 million

b. AEP's forecasted total and net revenues from wholesale sales to third parties (off-system sales allocated to operating companies) are:

	Total Revenue	Net Revenue
1999	$401.6 million	$180.1 million
2000	$616.5 million	$291.9 million
2001	$650.2 million	$301.4 million

c. No forecast of other revenue exists.

WITNESS: RICHARD E. MUNCZINSKI

17

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

For the years 1995, 1996, 1997, 1998 and 1999 to date, for Kentucky Power Company please:

a. provide the Moody's and S&P credit rating

b. list each credit rating upgrade, grade affirmation or downgrade and provide the reasons given by the rating agency for each

c. the current credit rating assigned to the Company by Moody's and S&P

d. the criteria employed by Moody's and S&P in establishing the current credit rating

e. provide copies of any credit alerts issued by Moody's or S&P

RESPONSE:

(a) First Mortgage Bonds

Year End	S&P	Moodys
1995	BBB+	Baa1
1996	BBB+	Baa1
1997	A	Baa1
1998	A	Baa1
1999 YTD	A	Baa1

Junior Subordinated Debenture ratings were established in 1995 at BBB and Baa3, respectively, and remain unchanged.

Senior unsecured Debt rating were established in 1997 at BBB and Baa2, respectively, and remain unchanged.

WITNESS: RICHARD E. MUNCZINSKI

RESPONSE CONTINUED:

(b) See item (a). See the attached information.

(c) See item (a).

(d) The criteria used by the rating agencies are in their publications which are copyrighted. Generally, they consider financial and operating factors, management and regulation among the factors.

(e) None regarding Kentucky Power.

WITNESS: RICHARD E. MUNCZINSKI

Kentucky Power Co.

Ratings

$253,500,000 First Mortgage Bonds	BBB+
Commercial Paper	F-2
Credit Trend	Stable

Analyst
John Watt
(212) 908-0523

Company Contacts
John S. Bilacic
Manager – Investor Relations
(614) 223-2847

Armando A. Pena
Vice President – Finance
(614) 223-2850

Commercial Paper Dealer
Merrill Lynch Money Markets Inc.

April 25, 1994

Summary

Ratings are affirmed on Kentucky Power Co.'s (KPC's) outstanding $235.5 million 'BBB+' first mortgage bonds and 'F-2' commercial paper. The credit trend is stable. The ratings reflect KPC's competitive rates, low-cost and abundant fossil-fired capacity, and capable management team, as well as excess leverage due to the lack of preferred equity, limited opportunity for sales growth, and heavy industrial load.

In 1993, KPC's average retail realization was 4.18 cents per kilowatt-hour (kwh) and, on average, industrial customers paid only 3.25 cents, far less than the regional average and beyond the competitive reach of nonutility generators. KPC operates the Big Sandy plant, which is low cost and complies with Phase I Clean Air Act (CAA) requirements. However, the plant's capacity concentration of 1,060 megawatts (mw) is a concern. Attractively priced capacity and energy are purchased from the Rockport generating units, which are owned by an affiliated company, at 2.69 cents per kwh.

KPC's management team has controlled costs despite the challenge of operating a distribution system in a rural, mountainous service territory. Further, KPC's access to the American Electric Power Co. Inc.'s (AEP)

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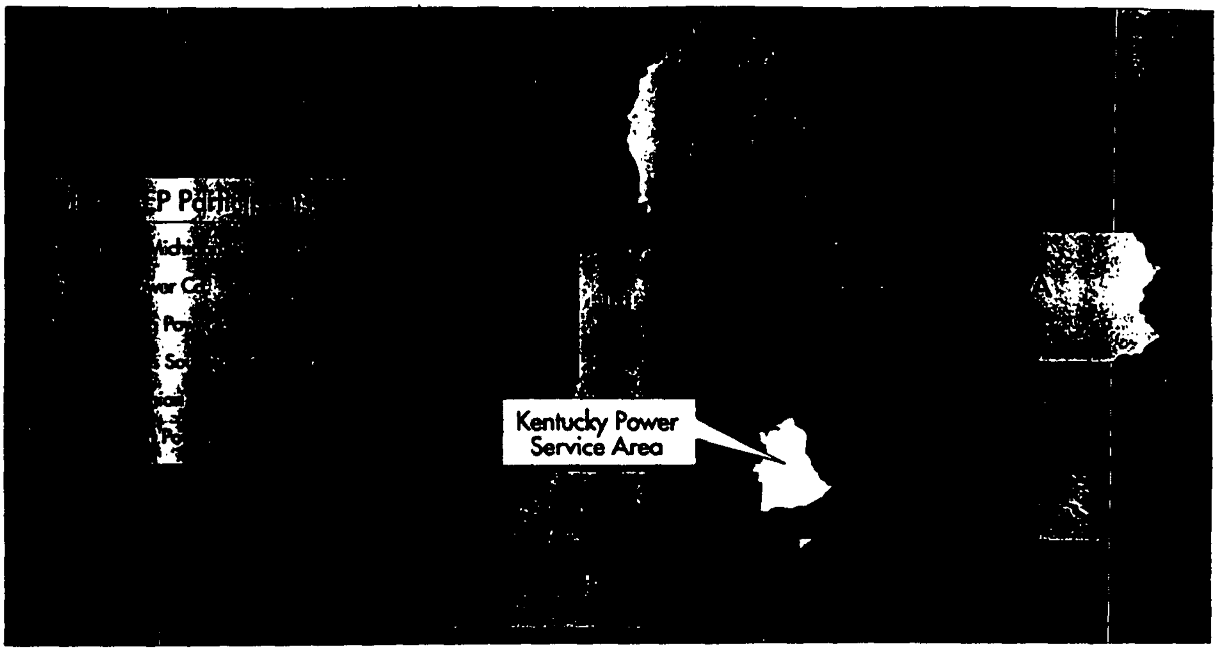
ESTABLISHED 1913



system resources provides operational and financial flexibility.

KPC's 1993 earnings eroded from previous levels, and current financial parameters are clearly weak for the rating category. Pretax interest coverage for the 12 months ended Dec. 31, 1993 was 1.95 times (x), and total debt was high at 60.0% of capitalization, partially due to the absence of preferred stock. Internal generation of capital expenditures was 45.2% for the year, approximating KPC's estimate for the upcoming four years. In 1994, operating income should improve somewhat as last year's major maintenance of Big Sandy will not recur and KPC will benefit further from reduced purchased power costs due to the plant's availability.

Nevertheless, KPC requires new base rate revenues to restore its financial parameters but has not yet announced a ratemaking strategy. Due to limited residential sales load and extensive low-margin industrial sales, KPC does not have the luxury to grow sales to match all costs associated with new distribution plant, CAA compliance, and accruals related to Financial Accounting Standard (FAS) 106.

Strengths

— Low-cost, abundant coal-fired generation.
— Competitive rates.
— Good environmental compliance.
— Nuclear-free operations.
— Access to parent for financial and operating resources.
— No nonregulated activities.

Risks

— Excess leverage; no preferred stock capital.
— Slow sales growth.
— Extensive industrial and coal mining load.
— Plant concentration in Big Sandy.
— Need higher base rates for (FAS) 106, Clean Air, higher service costs.

Demographics

KPC is one of the principal operating utilities wholly owned by the holding company, American Electric Power. KPC's service territory is located in eastern Kentucky; due to the mountainous region, KPC's transmission lines and distribution facilities are susceptible to damage by severe summer and winter storms.

KPC is a small utility providing service to only 158,000 customers drawn from a rural population of approximately 360,000. In general, the service territory's per capita income is well below state and national averages; Kentucky's nonmetropolitan per capita income was only $13,380 in 1991.

KPC's all-electric operations reflect moderate growth potential, with internal demand expected to increase by only 1.9% annually from 1994–1997. Industrial load is projected to grow at a 1.1% annual rate. This industrial customer group is important as it accounts for approxi-

Kilowatt-Hour Sales
(1993)

	Growth (%)	% of Sales	Cents/kwh
Residential	4.6	22.2	4.94
Commercial	3.8	11.6	5.21
Industrial	(1.2)	31.3	3.25
Total Retail	1.7	65.1	4.18
Wholesale	(24.1)	34.9	1.55

mately 50% of the internal sales load. Industrial revenues are significant, approximating $90 million, or about 30%, of $294.2 million in total 1993 revenues.

The principal industry served is coal mining. This energy-intensive user group dominates KPC's industrial load, with 1992 billings of $44.6 million derived from 1.05 billion kwh delivered. About 20 mining companies dominate the segment, and their businesses are vulnerable to shifting fuel consumption by end users.

KPC's next largest industrial segment is petroleum refining; one refiner, Ashland Oil, Inc., is KPC's largest customer. This segment consumed 857 million kwh at the very economical average price of 2.69 cents. The third largest segment is the primary metal industry, which includes KPC's second and third largest customers, ARMCO Inc. and Kentucky Electric Steel Co. This segment's 1992 demand was 590 million kwh priced at 3.36 cents/kwh.

AEP'S Clean Air Strategy

Phase I requirements (1995) are being addressed consistent with AEP's system planning. Due to the excessive sulphur dioxide emissions in AEP's Ohio operations, system compliance is concentrated on new scrubbers for Ohio Power's Gavin plant. AEP's decision to focus its clean air effort in Ohio is apparent in the table below.

KPC's remaining clean air expenditures in Phase I are minor at $10 million, relating to nitrogen oxide modifications at Big Sandy. KPC's sulfur dioxide emissions are well below AEP's system average and comfortably under the 1995 Phase I mandate of 2.5 pounds per million British thermal unit (mmBtu). For Phase II, KPC is expected to receive emission allowances from the AEP pool to meet more stringent requirements taking effect in 2000.

Electric Rates

KPC's rates are competitive in all customer segments, and, given the 10-year gap since the last rate increase, the company should be able to justify its current operating costs to the Kentucky Public Service Commission (KPSC). In 1993, KPC's average realization for residential kwh was 4.94 cents, with commercial at 5.21 cents and industrial at 3.25 cents. The politically sensitive residential rate is favorably positioned below that of other utilities in the state, such as Louisville Gas & Electric Co.'s 1992 rate of 5.97 cents/kwh and Kentucky Utilities' 5.27 cents/kwh.

Regionally, KPC's 1992 industrial rates per kwh compared favorably with neighboring low-price utilities such as Allegheny Power System, Inc. (3.77 cents), Cincinnati Gas & Electric Co. (4.44 cents), and Kentucky Utilities Co. (4.42 cents). Further, KPC is able and willing to provide

Sulphur Dioxide Emissions by State
(1991)

	Generation (Gigawatt-Hours)	Coal Consumed (Million Tons)	Sulfur Dioxide Emitted (lbs./ Million Btu)
AEP Total	97,209	42.4	3.10*
Indiana	20,287	11.3	1.28
Kentucky	5,043	2.0	1.64
Ohio	35,638	15.0	5.19
Virginia	5,191	1.9	1.28
West Virginia	31,049	12.1	2.39

*AEP average. Note: Numbers may not add due to weighting.

favorably priced energy to its high-volume customers, such as oil refiners, at prices averaging less than 2.8 cents/kwh.

Regulation

About 83% of KPC's revenues are regulated by the Kentucky Public Service Commission. Additionally, KPC is regulated by the Securities and Exchange Commission (SEC) since AEP, under the Public Utility Holding Company Act of 1935, is defined as a registered holding company. The SEC oversight concerns investments, asset sales, financing, and various intercompany transactions, such as the Rockport unit power agreement (UPA). The SEC is not directly involved in ratemaking.

KPC last received a general rate order in 1984. However, in 1991 the KPSC effectively reset the company's rates to lower the imputed authorized return on equity (ROE) to 13.5%. Currently, no regulatory issues are pending. KPC sought to defer accruing FAS 106 costs, but the KPSC declined the request pending review in a subsequent general rate case.

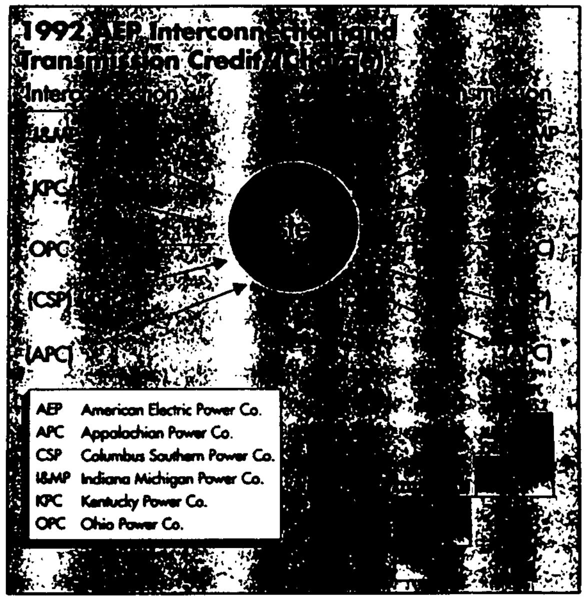
In 1992, the Kentucky Legislature enacted into law a provision that allows for current recovery of CAA compliance costs through the use of an "environmental surcharge." To date, no Kentucky utility has taken advantage of this rate device. KPC has a rate-tracking mechanism for variable fuel costs and fluctuating levels of off-system sales but has no adjustment for purchased power payments, or credits, determined for capacity in the interconnection agreement. Currently, KPC has moved to a deficient posture, due to an inordinately high peak and to Big Sandy's being off-line for major maintenance, but will return to its customary "long" position during 1994.

Due to the AEP interconnection agreement, KPC will be affected by Ohio Power Co.'s approximately $700 million obligation for Gavin scrubbers. When Gavin is completed in early 1995, Ohio Power starts its lease payments (about $70 million annually), with more than 50% of Ohio Power's payments to be recovered from KPC and other pool members that may be measured capacity deficient.

KPC's additional annual revenue requirement to meet the pool cost allocations plus current service costs and the new FAS 106 accrual expenses could entail one-time increases of 5%–9%. Should Ohio Power sell any emission allowances, the proceeds could moderate KPC's new revenue requirement.

Plant

KPC's generating plants and load centers are interconnected by an extensive transmission network with other AEP system companies to form an integrated power system. Important AEP subsidiaries in this power pool include: Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., and Ohio Power Co. KPC accesses and shares in the AEP system's generating and transmission capacity. Payments for capacity sharing and for energy are governed by the rules of the AEP system power pool — specifically, the interconnection agreement and a separate transmission agreement. Also, KPC is connected with non-affiliated regional utilities including Kentucky Utilities Co., the Tennessee Valley Authority, and East Kentucky Power Cooperative, Inc.



Since AEP operates its power generation and transmission functions as a single interconnected and coordinated system, installation of transmission lines and generating units is designed primarily to optimize consolidated operations and secondarily to address member companies' specific needs. Due to this system approach, KPC typically, but not currently, has sufficient capacity when viewed on a stand-alone basis. Through the interconnection agreement, KPC shifts its excess capacity to members of the AEP system that are capacity "short." As indicated in the graphic above, Columbus Southern Power and Appalachian Power, which are capacity deficient, make payment to the AEP pool to benefit KPC, Indiana Michigan, and Ohio Power, which were "long" on capacity in 1992.

To illustrate the financial impact of system arrangements to KPC, note in the table on the next page that KPC's 1992 "credit" related to generation and transmission was $30.2 million. This credit is derived by a formula that governs the flow of funds among the individual AEP utility units.

KPC is strictly an electric operation with generating capacity concentrated in two coal-fired stations, Big Sandy and Rockport. KPC has no nuclear involvement and no additions to generating capacity are under way.

AEP System Power Pool 1992 — Costs and Revenues
($ Mil.)

	Interconnection	Transmission	Total Credit/ (Charges)	Wholesale Profit	Overall Totals
Kentucky Power Co.	26	4.2	30.2	3.7	33.9
Appalachian Power Co.	(243.0)	(8.0)	(251.0)	18.1	(232.9)
Columbus Southern Power Co.	(118)	(29.9)	(147.9)	9.1	(138.8)
Indiana Michigan Power Co.	71	48.2	119.2	31.3	150.5
Ohio Power Co.	264	(14.5)	249.5	15.7	265.2
Total	0	0	0	77.9	77.9

Interconnection: Net credits/(charges) allocated under the interconnection agreement for capacity and economic energy.

Transmission: Net credits/(charges) allocated under the transmission agreement.

Wholesale Profit: Allocated profit contribution based on sales to non-affiliates.

The Big Sandy units aggregate 1,060 mw, with unit 1 contributing 260 mw and unit 2, 800 mw. The plant has low production costs of 1.42 cents/kwh. Big Sandy burns lower sulfur coal purchased from non-affiliated mining operations. Big Sandy 1 is the older unit, in commercial use since 1963, but both units are expected to remain operable for up to 30 more years.

In 1992, Big Sandy generated approximately 6.9 billion kwh and KPC purchased another 3.4 billion kwh. The purchases were made pursuant to a UPA with the AEP Generating Co. whereby KPC is obligated to take or pay for 15%, or 390 mw, of capacity and energy stemming from Rockport Generating Station. Rockport is operated by AEP subsidiary Indiana Michigan Power. This UPA will be in place until 1999, unless extended. The Rockport energy is excess to KPC's retail needs, which remain below 6 billion kwh, and the energy is resold to AEP Service for distribution within AEP or for sale to third parties.

KPC experienced its all-time internal peak demand, 1,309 mw, on Jan. 19, 1994, with reserve margin standing at 10.8%.

Management

Fitch considers KPC's management team fully capable of addressing the company's key challenges, which include maintaining good operations at Big Sandy, controlling expenses, and obtaining new rates more reflective of service costs. Management can draw on the professionals at AEP Service Co. to assist with legal, financial, economic development, marketing, engineering, and regulatory matters. Although AEP Service has been downsized and reorganized, these steps should not affect either the quality or timeliness of services provided to KPC.

Overall, AEP and KPC will continue to focus on cost reduction to defend the present level of competitive retail and wholesale rates and to minimize capital expenditures. Fitch does not anticipate AEP's moving, in the near future, to diversify in any significant fashion. AEP management has indicated that it would undertake any new nonregulated investment singly or in partnership with a major, experienced partner.

Financial

In 1993, KPC's operating income fell to $38.7 million from its three-year average of $50.2 million. With reduced operating profitability, ROE dropped to 9.25% from 13.5% in 1992 and pretax interest coverage was down markedly from the 3.06x recorded as recently as 1990. Negative factors included costs associated with the major maintenance at Big Sandy, higher interconnection costs, continued competitive pressure on AEP's wholesale volumes, accrual of FAS 106 costs, storm damage expense, and lack of ratemaking. In 1994, profitability should recover somewhat as KPC receives cash for returning to a capacity surplus position and as Big Sandy incurs no major maintenance.

During 1993, KPC issued $85 million in medium-term notes maturing from 2003 and 2023. Proceeds were used to pay off $55 million in previously outstanding unsecured bank debt. KPC entered 1994 with a manageable outstanding short-term debt position of $38 million. Pursuant to an SEC-approved shelf registration, $30 million remains for possible issuance of medium-term notes.

The capital expenditure budget for 1994 and 1995 has been reduced to $97 million from $115 million, thereby lowering the need to sell new debt. Previously, KPC's five-year forecast expected internal funds generation to meet only 50% of capital expenditures.

AEP did not put any new equity into KPC in 1993, and due to dividends exceeding available earnings, the retained earnings level dropped by $4.7 million. KPC expects AEP to increase its paid-in-capital by $35 million by 1996, starting with $10 million new capital in 1994.

With no preferred stock in its capital structure, KPC is highly leveraged, with total debt approximating 60%. KPC projects the capital structure to remain stable through 1997.

Financial Summary
($ Mil.)

	1993	1992	1991	1990	1989	1988	Five-Year Comp. Ann. Growth (%)
Balance Sheet Summary							
Total Capitalization	486.1	470.2	466.8	446.2	412.4	402.0	3.9
% Short-Term Debt	7.8	3.6	4.0	5.7	0.8	2.5	—
% Lease and Other Obligations	0.0	0.0	0.0	0.0	0.0	0.0	—
% Long-Term Debt (a)	52.1	54.0	54.5	52.6	56.9	58.4	(2.2)
% Total Debt	60.0	57.6	58.4	58.3	57.7	61.0	(0.3)
% Preferred Stock (b)	0.0	0.0	0.0	0.0	0.0	0.0	—
% Common Equity	40.0	42.4	41.6	41.7	42.3	39.0	0.5
Net Plant (c)	558.8	542.5	530.5	519.5	495.7	490.9	2.6
Income Statement Summary							
Operating Revenue	294.3	313.2	306.8	333.6	313.0	257.6	2.7
% Electric	100.0	100.0	100.0	100.0	100.0	100.0	—
Income Taxes (d)	1.6	1.5	5.7	10.8	12.9	7.1	(25.5)
Operating Expenses	255.5	265.0	256.5	281.6	256.8	211.0	3.9
Operating Income	38.7	48.3	50.3	51.9	56.1	46.5	(3.6)
Other Income	0.1	0.2	0.1	0.8	0.4	(1.0)	—
AFUDC (e)	0.0	0.0	0.0	0.7	0.2	0.1	(100.0)
Interest Charges	20.8	21.9	22.0	21.0	20.3	21.6	(0.8)
Nonrecurring Items	0.0	0.0	0.0	0.0	0.0	0.0	—
Net Income	18.0	26.5	28.5	32.5	36.3	24.1	(5.7)
Preferred Dividends	0.0	0.0	0.0	0.0	0.0	0.0	—
Net for Common	18.0	26.5	28.5	32.5	36.3	24.1	(5.7)
Funds Statement Summary							
Net Construction Expenditures	35.2	31.7	29.2	42.0	29.6	28.3	4.5
Funds from Operations (f)	15.9	22.4	26.3	28.0	34.2	23.0	(7.0)
Key Financial Statistics							
Pretax Interest Coverage (x) (g)	1.95	2.28	2.55	3.06	3.42	2.44	—
Excluding AFUDC (x) (h)	1.95	2.28	2.55	3.03	3.41	2.44	—
Preferred Dividend Coverage (x)	1.95	2.28	2.55	3.06	3.42	2.44	—
Excluding AFUDC (x) (h)	1.95	2.28	2.55	3.03	3.41	2.44	—
Return on Average Common Equity (%) (g)	9.2	13.5	15.0	18.0	21.9	15.7	—
Income Tax Rate (%)	8.2	5.2	16.6	25.0	26.3	22.6	—
% Internal Generation (i)	45.2	70.6	90.2	66.8	115.7	81.1	—
Gross Expenditures/Net Plant (%)	6.3	5.8	5.5	8.2	6.0	5.8	—
CWIP/Net Plant (%)	1.7	1.9	1.6	2.1	2.3	1.3	—
Internal Cash/Long-Term Debt (%) (j)	15.2	17.2	18.4	20.8	22.6	17.5	—
Return on Capital (%)	8.0	10.3	10.8	11.6	13.6	11.6	—
Operating Maintenance Exp. as % Revenue	76.2	74.5	71.8	72.0	68.8	68.2	—

(a) Includes current maturities of long-term debt and excludes lease and other obligations. (b) Includes preference stock. (c) Net plant in service (including construction work in progress). (d) Includes income taxes included in other income. (e) Allowance for funds used during construction. (f) Includes retained earnings, depreciation and amortization, deferred taxes, and ITC; excludes AFUDC. (g) Normalized for any writeoffs or extraordinary items. (h) Interest coverage excluding AFUDC also excludes any phase-ins. (i) Funds from operations (as defined) divided by net construction. (j) Internal cash in this ratio is before payment of dividends.

Attachment
Page 9 of 141
KPSC Case No. 99-149
KESI's (2nd Set)
Supplemental Request for Information
Item No. 17

Research

Kentucky Power Co.

Ratings (Taxable)
$179,000,000 First Mortgage Bonds.... BBB+
$40,000,000 Junior Subordinated Deferrable Interest Debentures.......... BBB–
Commercial Paper.............................. F-2
Credit Trend.............................. Declining
(Changed from Stable on 2/14/96)

Analysts
Michael T. Sagges
(212) 908-0579

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(212) 908-0523

Company Contacts
John S. Bilacic
Manager – Investor Relations
(614) 223-2847

Armando A. Pena
Senior Vice President – Finance and Treasurer
(614) 223-2850

Commercial Paper Dealers
Merrill Lynch Money Markets Inc.
Morgan Stanley & Co., Inc.

FITCH COMPETITIVE INDICATOR

Kentucky Power Co.	2.60
Average FCI Score	2.75

1 = Most Competitive   5 = Least Competitive

Summary

Kentucky Power Co.'s (KPC) ratings reflect the benefits KPC receives as a subsidiary of the American Electric Power Co., Inc. (AEP), including both financial and operational support, KPC's competitive electric rates, and low-cost, abundant coal-fired generation. However, the change in credit trend to declining from stable reflects the expected financial stress caused by the significant increase in capital expenditures planned for 1996, the associated increased debt requirement, and the lack of incremental revenue to cover the new investment.

As one of five principal wholly owned utility operating subsidiaries of AEP, KPC is part of one of the nation's largest electric utility companies, providing electric service to approximately seven million people in parts of Kentucky, Ohio, Michigan, Indiana, West Virginia, Virginia, and Tennessee. The AEP system owns or leases 23,759 megawatts (mw) of generating capability at 38 power plants and is connected to 29 other utilities. In 1995, AEP sold approximately 121 billion kilowatt-hours (kwh) of electricity and had operating revenues of nearly $5.7 billion, up from $5.5 billion in the previous year.

KPC's retail rates are among the lowest in its general operating region. Its average retail realization was $0.041 per kwh during 1995's first 10 months, while the average industrial rate

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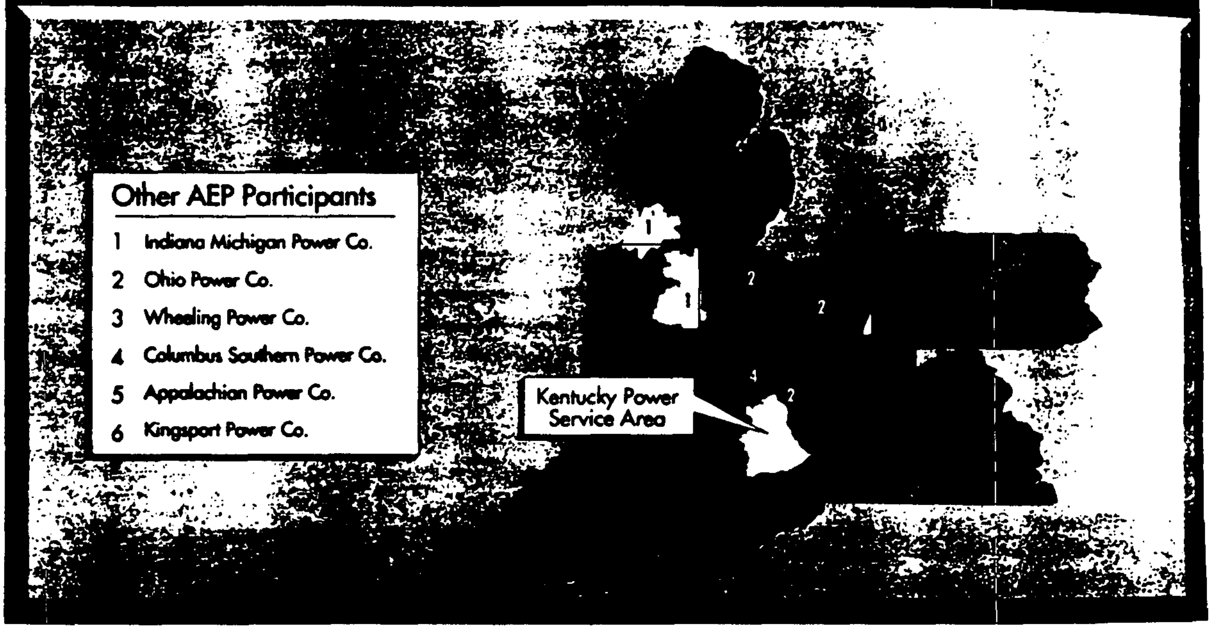
Kentucky Power Service Area and American Electric Power System



of $0.032 per kwh favorably positions the company for the competitive future. KPC owns and operates only one 1,060-mw coal-fired generating plant. Capacity and energy are also purchased from the Rockport plant, which is owned and leased by affiliates of KPC, for approximately $0.024 per kwh. The concentration of the company-owned generation in one plant is partially mitigated by KPC's access to the AEP generating system.

KPC is moving forward with an extensive capital expenditure program in 1996, which primarily consists of constructing a new transmission line and upgrading the existing transmission system. Fitch expects a significant portion of this program to be funded with new debt and a capital contribution from AEP and does not anticipate that KPC will file for an increase to base rates to cover this investment.

Strengths

— Access to AEP generating assets and transmission system.
— Competitive rates.
— Low-cost, abundant coal-fired generation.
— No nuclear exposure.

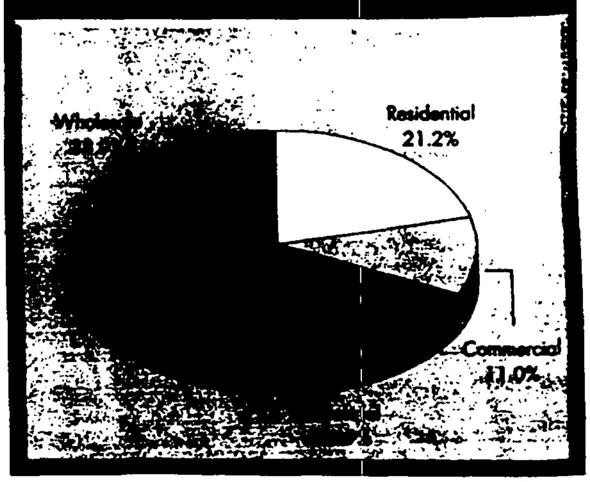
Risks

— Additional debt required to fund capital expenditures.
— Extensive industrial and coal mining load.
— Little opportunity for sales growth in service territory.
— Concentration of generating resources in one plant.
— Above-average reliance on short-term debt.

Demographics

KPC is engaged in the generation, transmission, and distribution of electric capacity and energy to approximately 165,000 retail customers in eastern Kentucky. The

1995 Kilowatt-Hour Sales Mix



Rate Comparison — 1995 Average Rates
(Cents per kwh)

	Residential	Commercial	Industrial
Kentucky Power Co.	4.94	5.16	3.15
Kentucky Utilities Co.	4.62	4.41	3.42
Appalachian Power Co.	5.75	5.14	3.68
Louisville Gas & Electric Co.	5.96	5.57	3.69
Monongahela Power Co.	7.62	6.45	4.26
Cincinnati Gas & Electric Co.	7.81	6.80	4.61

Source: *Resource Data International, Inc.* first 10 months of 1995.

company also sells and transmits wholesale power to AEP affiliates and other electric utilities and municipalities in Kentucky. KPC's eastern Kentucky service territory is a rural, mountainous region in which the significant industrial employers are involved in coal mining, petroleum refining, primary metals, and chemicals. An unemployment rate of nearly 8.0% (as of March 1995) exceeded the overall Kentucky unemployment rate of 5.0% and the national average of 5.7%. In 1995, KPC's residential customer base increased by approximately 1.3% and its commercial customer base by about 1.8%, in line with industry average growth of 1.4% and 1.7%, respectively. Conversely, the number of industrial customers decreased by 4.0% versus an industry average decline of less than 1.0%.

As exhibited in the pie chart on page 2, KPC's residential sales accounted for 21.2% of total kwh sold in 1995, commercial constituted 11.0%, the industrial load was 28.9%, and wholesale sales to AEP affiliates and unaffiliated utilities accounted for another 38.9%. The growth in kwh sold exceeded projections for all customer classes in 1995. The company forecasts continued growth in the sale of units in 1996 to each of its customer groups, albeit at more moderate growth rates.

The industrial load is composed of a heavy concentration of sales to the coal mining industry and secondarily to the oil refining industry. In 1995, sales to industrial customers accounted for 29.5% of total operating revenues and 36.7% of retail operating revenues. According to the 1994 Uniform Statistical Report, 38.9% of KPC's industrial load was sold to the coal mining sector and 31.0% to petroleum refining and related industries. Although there are various companies operating coal mines in KPC's service territory, this is viewed as a high concentration by a single industry for the company's output.

Rates

KPC's rates are quite competitive when viewed in relation to neighboring electric utilities inside and outside of Kentucky *(see table above)*. The company's average realization for residential and commercial rates for 1995's first 10 months, at $0.049 per kwh and $0.052 per kwh, respectively, was lower than the average rates of all the noted companies except that of Kentucky Utilities Co. The average commercial rate is similar to that of Appalachian Power Co. (APC), another AEP system company. KPC's average industrial rate, at $0.032 per kwh, was the lowest industrial rate of all the regional investor-owned utilities.

The average industrial rate for a large-volume user on the KPC system ranged from $0.039 per kwh, for coal mining down to an average price of approximately $0.026 per kwh for petroleum refining. KPC's current low rates are likely to make the company less vulnerable to competition as the industry moves toward deregulation.

Regulation

More than 80% of KPC's revenues are from retail sales, which are regulated by the Kentucky Public Service Commission (KPSC), while the balance, wholesale power sales, is regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act for rates for interstate sale at wholesale and transmission. KPC is also regulated by the Securities and Exchange Commission (SEC), since AEP is defined as a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA).

KPC's regulatory environment is viewed as slightly above average by Fitch. The KPSC is not involved in significant restructuring/retail wheeling activity to date, and it is more likely that the regulatory body will focus its reform primarily on performance-based ratemaking and rate design modifications, which will assist industrial customers' competitiveness. It is Fitch's opinion that electric industry reform in Kentucky is not a fast-track issue.

Certain large industrial companies, primarily aluminum companies in western Kentucky, were drafting retail wheeling legislation in 1994, reportedly in response to high prices from Big Rivers Corp. However, Fitch notes that there are no bills currently pending.

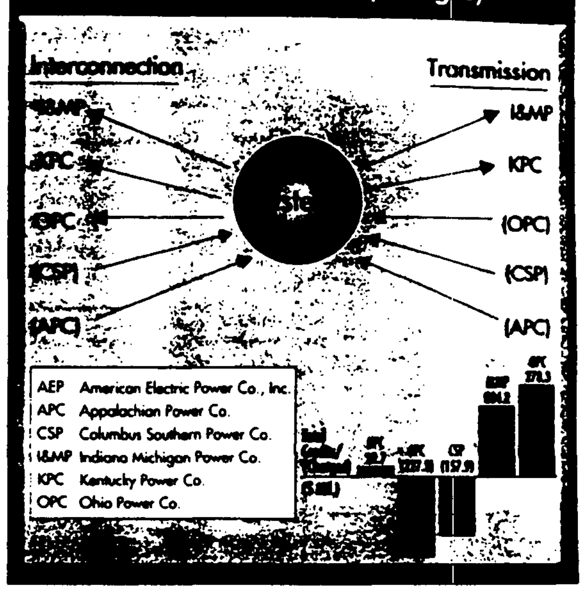
KPC's last general rate order was in 1984; however, in 1991, the KPSC required the company to reduce its rates by $11.5 million. Currently, no regulatory issues are pending.

In 1994, the Kentucky Legislature passed legislation that allows for electric utilities to recover the full costs of demand-side management programs and provides for incentives that will encourage implementation of cost-effective demand-side management. In December 1995, the KPSC issued an order approving a three-year demand-side management plan, which will end Dec. 31, 1998. Under the plan, program costs, net lost revenues, and incentives will be recovered from an annual surcharge tariff. The plan covers programs for residential, commercial, and industrial sectors.

Plant

One of KPC's principal strengths is that the company is interconnected to the overall AEP system of generation and transmission facilities. The AEP system companies, which include APC, Columbus Southern Power Co. (CSP), Indiana Michigan Power Co. (I&MP), and Ohio Power Co. (OPC), run their generating plants and transmission lines as a single, interconnected system. Each company can access the system's generation and transmission capacity. Revenues and costs related to the system's generating plants and each subsidiaries' purchase of system capacity and energy are defined within an interconnection agreement. In addition, KPC is party to a transmission agreement that specifies how the costs of the transmission system are shared among the AEP subsidiaries. Moreover, AEP's subsidiaries have entered into an interim allowance agreement, accepted by the FERC on Dec. 30, 1994, that provides a mechanism for the allocation of emission allowances and the financial value for those emission allowances to the generating companies of the AEP system. This agreement does not include the purchase and sale of such allowances to and from non-affiliated parties. KPC is also

1995 AEP Interconnection and Transmission Credits/(Charges)



connected with some unaffiliated utilities — Kentucky Utilities, East Kentucky Power Cooperative, Inc., and Tennessee Valley Authority.

Since AEP operates its power generation and transmission functions as a single, interconnected and coordinated system, installation of transmission lines and generating units is designed primarily to optimize consolidated operations and, secondarily, to address member companies' individual needs. Members of the AEP system with excess capacity direct it to those that are short on capacity. As indicated in the chart above, APC and CSP, which were

AEP System Power Pool — 1995 Costs and Revenues
($ Mil.)

	Interconnection/ Interim Allowance*	Transmission†	Total Credits/ Charges	Wholesale Profit‡	Transmission Non-Affiliates^	Overall Total
Kentucky Power Co.	23.0	3.5	26.5	5.0	1.2	32.7
Appalachian Power Co.	(252.0)	(5.4)	(257.4)	24.1	6.0	(227.3)
Columbus Southern Power Co.	(143.0)	(31.1)	(174.1)	12.0	4.2	(157.9)
Indiana Michigan Power Co.	118.0	46.7	164.7	34.7	4.8	204.2
Ohio Power Co.	254.0	(13.7)	240.3	20.2	17.8	278.3
Total	0.0	0.0	0.0	96.0	34.0	130.0

*Interconnection agreement and interim allowance agreement – Net credits/charges allocated under the interconnection agreement for capacity and economic energy, and under interim allowance agreement for transfer of sulphur dioxide allowances associated with transactions under the interconnection agreement. †Transmission – Net credits/charges allocated under the transmission agreement. ‡Wholesale profit – Allocated profit contribution based on sales to non-affiliates. ^Transmission services for non-affiliates – Allocated profit contribution based on transmission services for non-affiliated companies.

capacity deficient in 1995, made payments to the AEP pool to benefit KPC, I&MP, and OPC, which provided capacity to the system.

To illustrate the financial impact of the system arrangements to KPC, note in the table at the bottom of page 4 that KPC's 1995 credit related to generation and transmission was $26.5 million. This credit is derived by a formula that governs the flow of funds among the individual AEP system companies.

Within the context of the AEP system arrangements described earlier, KPC wholly owns and operates Big Sandy, a two-unit, 1,060-mw coal-fired generating station. The fuel burned at Big Sandy is low-sulfur coal purchased substantially from unaffiliated producers under both long-term contracts and on the spot market. The first unit of Big Sandy went into service in 1963, and the second unit was placed into service in 1969. Variable production costs for the plant are low, amounting to 1.44 cents per kwh in 1994. It is estimated that these generating units will operate for approximately 30 more years.

In addition to Big Sandy, KPC has a long-term contract for 390 mw of capacity and energy from the Rockport Plant, a two-unit, 2,600-mw coal-fired plant that is owned and leased in part by affiliates I&MP and AEP Generating Co. The two Rockport units went on line in 1984 and 1989. Pursuant to a unit power purchase agreement with AEP Generating, which expires Dec. 31, 1999, KPC is obligated for the capacity payments whether or not the company takes the power. Because of industry restructuring, it is uncertain at this time whether KPC will sign a long-term contract for capacity from Rockport when the current contract lapses or whether AEP will look to sell the electricity outside of its system.

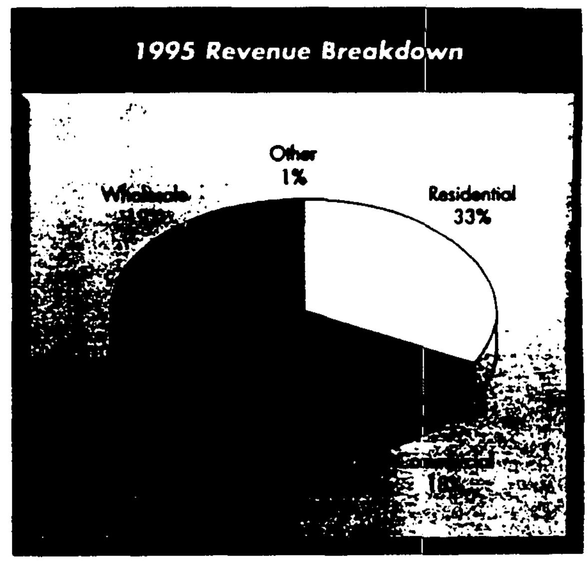
In 1995, the Big Sandy plant generated approximately 7,318 million kwh of electricity, and KPC purchased 3,437 million kwh from the AEP power pool and unaffiliated entities. Of the amount generated and purchased, the company sold nearly 6,317 million kwh of retail and approximately 4,025 million kwh of wholesale. These amounts were up from 5,977 million kwh of retail and 3,304 million kwh of wholesale sold in 1994.

The all-time one-hour peak demand for KPC was 1,418 kilowatts (kw) on Feb. 5, 1996, which left a reserve margin of only 2% if measured solely by the capacity of Big Sandy and KPC's contract with Rockport. However, as part of the AEP system, KPC has access to significant additional generating resources. Neither KPC nor the AEP system has plans to add any new generation until after 2000.

Financial

KPC's operating revenues rose by approximately 7% to $328.1 million in 1995, due primarily to increases in energy sales to retail and wholesale customers of 6% and 22%, respectively. Warmer summer weather and a colder fourth quarter in 1995 as compared to 1994, as well as an increase in the number of residential and commercial customers, accounted for the growth in retail sales. Wholesale energy sales, primarily to the AEP system power pool, rose on higher demand from both affiliated and unaffiliated utilities. Sales to unaffiliated utilities were primarily short-term, low-margin sales.

Operating expenses also were up in 1995 due to a significant increase in fuel expense, reflecting 25% greater net generation from Big Sandy (both of the Big Sandy generating units underwent scheduled boiler inspection



and repairs in 1994, while major maintenance was performed on only one unit in 1995) and the provision for severance pay related to a planned staffing reduction at Big Sandy and KPC's share of a staffing reduction at Rockport. Still, operating income rose to $49.0 million in 1995 from $46.1 million in 1994.

An increase in interest expense, primarily resulting from the issuance of $40 million of junior subordinated deferrable interest debentures in 1995, caused net income to remain relatively unchanged at $25.1 million from one year earlier.

Some actions were taken to bolster KPC's capitalization ratios in 1995, including the issuance of the junior subordinated debt and a $10 million capital contribution from AEP; however, the company's financial condition remained relatively unchanged from the prior year. KPC's debt-to-capitalization ratio improved to 53% at Dec. 31, 1995 from 60% at Dec. 31, 1994, yet pretax interest coverage declined to 2.2 times (x) from 2.3x as the interest expense increased. In addition, the debt required to fund a sizable planned 1996 capital expenditure program will put increased pressure on the company's financial condition in the near term. Furthermore, the high dividend payout ratio, which approximated 91% of net earnings in 1995, 85% in 1994, and exceeded net earnings in 1993, limits the growth in KPC's retained earnings.

Since the junior subordinated debentures are subordinate to all debt, the interest payments may be deferrable for up to five years, and the debentures mature in 2025, Fitch treats 80% of the value of the debentures as a preferred stock equivalent and 20% as debt for analysis purposes *(see Fitch Research on "Rating Hybrid Securities," dated December 11, 1995)*. As the security nears maturity, its value as an equity equivalent is diminished and it will eventually be analyzed purely as debt.

KPC anticipates initiating an unusually large capital expenditure program in 1996, which includes constructing new transmission lines, replacing existing transmission lines, and adding a unified power flow controller (UPFC). UPFC is a new technology designed to improve transmission system stability. Capital expenditures in 1996 are expected to approximate $85 million, up from $39 million in 1995. The majority of the transmission upgrade will occur in 1996 rather than over a span of three to four years, as originally planned. Fitch expects that the capital expenditures will be funded primarily by up to $50 million of new debt and a $30 million capital contribution from AEP. AEP already provided $10 million in capital contributions to KPC in both 1994 and 1995. KPC's capital expenditures from 1996–1998 are estimated at $210 million, versus approximately $128 million from 1993–1995.

Short-Term Credit Arrangements

Short-term debt, composed of notes payable and commercial paper, stood at $27 million at year-end 1995, versus approximately $55 million at year-end 1994. KPC is authorized under provisions of PUHCA, as administered by the SEC, to issue up to $150 million in short-term debt, a $50 million increase from one year earlier. Lines of credit, which are shared with the other AEP system companies, approximate $500 million.

Daily average commercial paper outstanding in 1995 ranged from $22 million–$33 million. The maximum amount of commercial paper outstanding at any one point during the year totaled nearly $58 million. During this same quarter, KPC also reached a maximum of more than $62 million in notes payable outstanding. It is KPC's practice to finance current capital expenditures in excess of internally generated funds with short-term debt and then reduce the short-term debt with both long-term debt and capital contributions from AEP. However, while it is within the regulatory bounds set by PUHCA and follows company operating standards, Fitch views the high base level of short-term debt used by KPC in relation to the size of the company as a concern.

Management

In the face of dramatic change in the electric utility industry, AEP has taken a number of steps to prepare itself for a competitive future. This included a realignment in the company structure from separate operating company organizations to functional business units — power generation, nuclear generation, energy delivery, and corporate development. While this action should facilitate the potential unbundling of generation services from transmission and distribution services, it is also intended to help AEP meet its customer needs more effectively, streamline operations, and reduce costs. AEP has also proposed the creation of an independent system operator (ISO), which would independently manage a multistate transmission grid. Furthermore, the company supports a regional power exchange, which would establish a competitive marketplace for generation and provide all customers with the benefit of market-based pricing. Through such proposals, AEP's management is attempting to actively participate in directing the changes in the regulated utility industry rather than just being affected by the inevitable restructuring.

As of Jan. 1, 1996, each of AEP's subsidiaries began operating under the name AEP rather than by their previous corporate names (e.g. Kentucky Power) to enhance the company's market recognition. There has been no change to the legal names of the operating subsidiaries nor to the legal, financial, rate, or regulatory relationships of AEP and its subsidiaries. As the regulated electric utility industry moves to a competitive marketplace, AEP sees value in a single brand name that will help to foster growth of its services both in and outside of the company's current sales territory.

Financial Summary
($ Mil.)

	Years Ended Dec. 31					
	1995	1994	1993	1992	1991	1990
Balance Sheet Summary						
Total Capitalization	540.2	517.1	486.1	470.2	466.8	446.2
% Short-Term Debt	5.0	10.7	7.9	3.6	4.0	5.7
% Long-Term Debt (a)	48.4	49.0	52.2	54.0	54.5	52.6
% Total Debt	53.4	59.7	60.0	57.6	58.4	58.3
% Preferred Stock (b)	5.8	0.0	0.0	0.0	0.0	0.0
% Common Equity	40.8	40.3	40.0	42.4	41.6	41.7
Net Plant (c)	609.1	591.9	558.8	542.5	530.5	519.5
Income Statement Summary						
Operating Revenue	328.1	307.4	294.3	313.2	306.8	333.6
% Electric	100.0	100.0	100.0	100.0	100.0	100.0
Income Taxes (d)	3.9	2.2	1.6	1.5	5.7	10.8
Operating Expenses	279.1	261.4	255.5	265.0	256.5	281.6
Operating Income	49.0	46.1	38.7	48.3	50.3	51.9
Other Income	0.0	(0.1)	0.1	0.2	0.1	0.8
AFUDC (e)	0.0	0.0	0.0	0.0	0.0	0.7
Interest Charges	23.9	20.7	20.8	21.9	22.0	21.0
Nonrecurring Items	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	25.1	25.3	18.0	26.5	28.5	32.5
Preferred Dividends	0.0	0.0	0.0	0.0	0.0	0.0
Net for Common Stock	25.1	25.3	18.0	26.5	28.5	32.5
Funds Statement Summary						
Net Construction Expenditures	39.3	53.1	35.2	31.7	29.2	41.7
Funds from Operations (f)	22.9	24.3	15.9	22.4	26.3	28.0
Key Financial Statistics						
Pretax Interest Coverage (x) (g)	2.22	2.33	1.95	2.28	2.55	3.06
Return on Average Common Equity (%) (g)	11.7	12.5	9.2	13.5	15.0	18.0
% Internal Generation (h)	58.3	45.8	45.2	70.6	90.2	66.8
Gross Expenditures/Net Plant (%)	6.5	9.0	6.3	5.8	5.5	8.2
Internal Cash/Long-Term Debt (%) (i)	17.5	18.0	15.2	17.2	18.4	20.8
Dividend Payout – Common Stock (%)	91.2	84.7	125.8	80.5	71.9	64.5

(a) Includes current maturities of long-term debt and junior subordinated debt and excludes lease and other obligations. (b) Includes 80% of the junior subordinated debentures treated as preferred equity. (c) Net plant in service (including construction work in progress). (d) Includes income taxes included in other income. (e) Allowance for funds used during construction. (f) Includes retained earnings, depreciation, amortization, deferred taxes, and ITC, excludes AFUDC. (g) Normalized for any writeoffs or extraordinary items. (h) Funds from operations (as defined) divided by net construction expenditures (i) Internal cash in this ratio is before the payment of dividends.

[illegible]

Ratings	Security Class	D&P	Latest Change	Prior
	First Mortgage Bonds	BBB	12/88	BBB
Rating Watch:		No		No

Rating Rationale

Debt protection measures have declined largely due to higher operating and maintenance expenses. Increased competition and the weak economy have limited off-system sales in recent years. However, Kentucky Power's rates are very competitive. External new money financing will be required for construction expenditures through 1996, mostly for transmission and distribution improvements. The long-term agreement with affiliate AEP Generating Company to purchase 390 mw of capacity from the Rockport Plant reduces reported coverages and increases leverage.

Short-Term Outlook

Credit protection measures should remain relatively stable with a combination of debt and equity expected to finance new money needs.

Recent Developments

Lower unit availability due to scheduled maintenance at Unit 2 of the 1,600 mw Big Sandy Plant and availability from an affiliate's nuclear units resulted in lower wholesale sales and increased purchased power expense. A 6/93 windstorm con- [illegible] which includes the installation of scrubbers at Ohio Power's Gavin station. Recovery of CAA costs could put upward pressure on rates. However, Kentucky Power's existing rates are low for the region, providing some cushion competitively.

Major Risks

The potential for rising fuel costs is [illegible] regulatory support for recovery of capital expenditures will be [illegible]. A continuation of the weak economy may pressure earnings and coverage.

Fundamentals

	Contribution %		
	Rev.	Op. Inc. %	Jurisdiction-% Revenue
Elec	100	100	KY-80, FERC-20

[illegible]

Avg. Elec. Unit Prices—Retail (Cents/kwh)					
Res.		Comm.		Ind.	
Co.	Rgn.	Co.	Rgn.	Co.	Rgn.
4.9	7.5	5.2	7.1	3.2	4.7

Avg. Elec. Unit Cost Generation (Cents/kwh)		1994-1996	
Co.	Rgn.	Constr. ($)	153MM
2.1	3.3	Capital	Stable
		Int. Cash/Cons. (%)	Decr.

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Item No. 17

55 EAST MONROE STREET • CHICAGO, ILLINOIS 60603 • (312) 368-3131 • FAX (312) 368-3155

Global

Utilities

Rating

Service

Utility Credit Report

KENTUCKY POWER CO.

Analyst: Steve Zimmerman, New York (1) 212-208-1658

Corporate Credit Rating

BBB+/Stable/—

Business Profile

1 2 3 [4] 5 6 7 8

strong — weak

Outstanding Ratings

Kentucky Power Co.	
Sr secd debt	BBB+
Sub debt	BBB
Appalachian Power Co.	
Sr secd debt	A-
Sr unsecd debt	BBB+
Sub debt	BBB+
Jr sub debt	BBB+
Pfd stk	BBB+
Indiana Michigan Power Co.	
Sr secd debt	BBB+
Sr unsecd debt	BBB
Sub debt	BBB
Pfd stk	BBB
RGS (I&M) Funding Corp.	
Sr unsecd debt	BBB
Ohio Power Co.	
Sr secd debt	A-
Sr unsecd debt	BBB+
Sub debt	BBB+
Pfd stk	BBB+
RGS (AEGCO) Funding Corp.	
Sr unsecd debt	BBB
Columbus Southern Power Co.	
Sr secd debt	A-
Sr unsecd debt	BBB+
Sub debt	BBB+
Pfd stk	BBB+
Columbus & Southern Ohio Electric Co.	
Sr secd debt	A-

Corporate Credit Rating History

Nov. 15, 1988	BBB+
Jan. 23, 1985	BBB
May 16, 1983	BBB+
Oct. 22, 1976	A
Jan. 7, 1972	BBB

Company Contact

John Bilacic (1) 614-223 2847

RATIONALE

Kentucky Power Co.'s (KPCo) ratings largely reflect the above average business profile and adequate financial position of parent American Electric Power Co. (AEP). The AEP system is physically interconnected, with management, operations, and financial policies coordinated at the parent level. Both KPCo's stand-alone and AEP's consolidated financials are expected to be relatively stable going forward. KPCo's creditworthiness is enhanced by its membership in the AEP system. The Kentucky Public Service Commission (PSC) approved a settlement agreement providing for full recovery of costs associated with Rockport unit power purchases and transmission equalization payments. Previously, the Kentucky commission had limited recovery to the less expensive AEP power pool embedded cost rate rather than the more costly Rockport unit power agreement. Still, KPCo's interest coverage and capitalization ratios after adjusting for capacity payments associated with long-term contracted Rockport power purchases are weak, but are supported by the system's stronger financial condition. For the next five years, projected KPCo spending will require significant external funding, which will pressure financials. Common equity infusions from parent AEP will be needed to maintain a balanced capital structure.

AEP system internal funds generation and cash interest coverage are expected to remain adequate, although debt leverage continues to be aggressive. AEP challenges include increasing wholesale profitability, a cyclical industrial load, strict state rate regulation, and Clean Air Act requirements.

OUTLOOK

Strong consolidated AEP operations provide ratings stability and support for maintenance of KPCo's credit quality. Significant capital spending relative to KPCo's size and cash flow generation capability will restrain credit improvement for this AEP subsidiary. Clean air spending, purchased power, and lackluster projected retail sales growth add risk but are largely reflected in ratings.

[illegible]

	1997*	1996	1995	1994	1993
Gross revenues	323.3	323.3	328.1	307.4	294.3
Net income from continuing operations	22.0	20.5	25.1	25.3	18.0
Funds from operations (FFO)	43.8	38.7	48.0	45.0	34.0
Net cash flow	15.5	11.0	22.4	23.6	11.3
Capital expenditures	80.7	75.8	38.9	52.6	35.0
Total capital	598.1	614.0	591.9	527.0	494.3
Adjusted ratios					
Pretax interest coverage (x)	2.37	2.26	2.32	2.26	1.91
Total debt/total capital (%)	52.3	53.9	56.1	60.6	60.8
FFO interest coverage (x)	3.17	3.11	3.31	3.09	2.53
FFO/avg. total debt (%)	13.7	11.8	14.8	14.6	11.4

*For 12 months ended March 31 (unaudited).

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BUSINESS DESCRIPTION

KPCo is one of the five major operating subsidiaries of the AEP system. AEP is a registered public utility holding company that owns directly or indirectly all of the common stock of its operating electric utility subsidiaries, including Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., and Ohio Power Co. (OPCo). The service area of AEP's electric subsidiaries contains seven million people and covers portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The total AEP service territory covers 45,400 square miles. The generating and transmission facilities of AEP's subsidiaries are interconnected, and its operations are coordinated as a single integrated electric utility system. Substantially all of the AEP system's operating revenues are derived from providing electric service.

AEP has realigned its organization structure to create a distinct power generation group and an energy transmission and distribution group. Currently, however, there are no changes in asset ownership or formal legal entities. In addition, AEP plans to offer an extensive array of services outside its traditional service territory and regulated business lines. Performance improvements are also planned, such as increasing the availability of AEP generating units, reducing fuel costs, increasing efficiencies in purchasing and materials management, implementing an activity-based management system, and investing in new technology and employee development.

Furthermore, AEP is phasing out its operating company identification. Management intends to enhance brand loyalty to the AEP name because of increasing competition and deregulation.

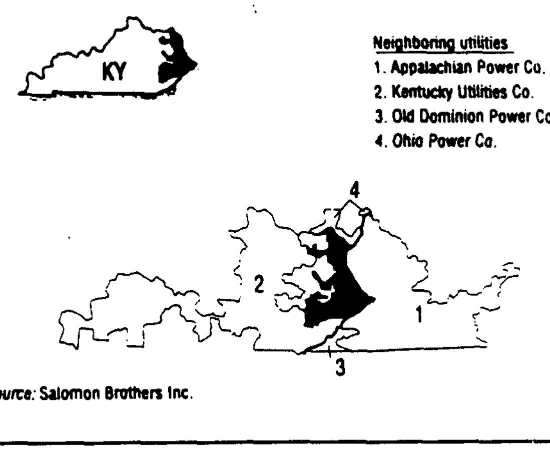
On a consolidated basis, AEP's overall creditworthiness is viewed as in between a weak 'A-' and a strong 'BBB+', given a favorable business position evaluation. Thus, the senior secured debt of the operating subsidiaries will tend to be in the 'BBB+' to 'A-' range.

AEP continues to study nonregulated business opportunities, particularly those that relate to the company's electric expertise. Such endeavors are conducted through AEP Resources Engineering & Services Co. and AEP Resources Inc.

AEP Energy Services offers various consulting services, both domestically and internationally, that relate to the company's electric expertise. AEP Resources' primary business is the development and investment in exempt wholesale generators, foreign utility companies, qualifying cogeneration facilities, and other power projects. In 1996, a new unregulated subsidiary, AEP Communications Inc., was formed to seek opportunities in the telecommunications industry. This new subsidiary will provide installation, maintenance, and engineering services for companies that provide wireless personal communications services and competitive long exchange services.

In early 1997, AEP and Public Service Co. of Colorado (PSCo) acquired Yorkshire Electricity Group PLC (AA/Watch Neg/—), a British regional electric distribution company (REC), for $2.4 billion. To execute the acquisition, AEP and PSCo formed a 50/50 joint venture company, Yorkshire Holdings PLC, under their unregulated entities, AEP Resources and New Century International Inc. About $1.7 billion was borrowed by Yorkshire, without legal recourse to any of the domestic entities. The remaining $720 million, or about $360 million each, was borrowed by domestic

KENTUCKY POWER CO.



Source: Salomon Brothers Inc.

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units of AEP and PSCo to fund their equity investment in Yorkshire Power Group Ltd.

Yorkshire is one of 12 RECs in the U.K. Headquartered in Leeds (about 250 miles northeast of London), it serves 2.1 million customers in northeast England. Overall, Yorkshire appears to be a relatively low-risk investment with solid earnings, sales growth potential, and a stable regulatory environment. In addition, the bulk of the acquisition debt is legally nonrecourse to AEP and PSCo. Standard & Poor's attributed a portion of this debt to the consolidated financials of the buyers, premised on the assumption that neither AEP nor PSCo would permit Yorkshire to default on debt service. Moreover, the borrowing costs associated with short-term financing of the equity portion will lower consolidated coverage ratios over the near term for both utilities. AEP is expected to use the proceeds from its new issue dividend reinvestment program of about \$75 million annually to pay down this \$360 million recourse transaction-related debt. Recently, the U.K. proposed a one-time windfall profits tax on privatized U.K. utilities. AEP's share of the proposed tax is estimated at about \$111 million. AEP is currently assessing the net earnings effect of the proposed tax, which is expected to be recorded in the third quarter of 1997.

Although AEP had the debt capacity to finance this acquisition without significant credit impact, this relatively large acquisition will restrain AEP's domestic financing flexibility and divert management attention.

AEP Resources entered into an agreement with Chinese partners to develop, build, and own a 70% interest in two 125MW coal-fired units in Henan Province, China. AEP's share of the total cost of the facility is about \$110 million, and the project is expected to be operational in 1999.

AEP Resources entered into a strategic alliance with Cogentrix Energy Inc. to develop, own, and operate industrial power projects in the U.S. and Canada. AEP Resources is also studying investment opportunities in new and existing generation equipment in Australia, Mexico, and India.

AEP has received approval from the SEC under the Public Utilities Holding Company Act of 1935 (PUHCA) to finance up to \$300 million for investment in exempt wholesale generators and foreign utility companies. AEP also has approval to finance up to 50% of its consolidated retained earnings (over \$750 million) in exempt wholesale generators and foreign utility companies. AEP has requested authority from the SEC to finance up to 100% of its consolidated retained earnings in nonregulated investments. AEP has authority from the SEC under PUHCA to invest up to \$100 million in subsidiaries engaged in the marketing of energy commodities, including electricity and gas.

BUSINESS PROFILE

Regulation. Retail rates are regulated by the KPSC, while wholesale rates are regulated by the Federal Energy Regulatory Commission. For the next few years, absent a major construction program, the company's rate relief requirements should be manageable. The bulk of base rate needs center on recovery of AEP

Regulation

Regulatory agency	Kentucky Public Service Commission	
State	Kentucky	
Case period	Six months.	
Interim procedures	Rarely	
Authorized returns (last 12 to 18 months)		
Return on equity (electric)	11.50	
Return on equity (gas)	11.50	
Return on equity (telephone)	0.00	
Rate base	Average original cost.	
Test period	Forecast.	
CWIP	CWIP included in rate base for full cash return	
Adjustment mechanisms	Fuel and purchased power adjustment clauses (automatic)—the energy component of purchased power is recovered through the fuel clause. The capacity component is recovered through base rates; gas cost adjustment clause permitted monthly based upon actual costs for the second preceding month, with an under-/over-recovery mechanism included.	
Incentive ratemaking	Rate of return	
Commissioners	Party	Term
Linda Breathitt, Chair	Democrat	July 1997
Edward J. Holmes	Democrat	July 1999
Brenda J. Helton	Democrat	July 2001

Source: Regulatory Research Associates Inc.

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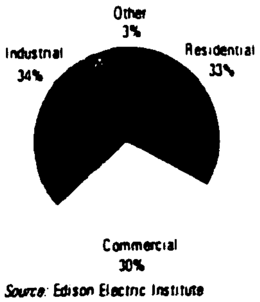
Industry Retail Sales (MWh)
1995



Source: Edison Electric Institute

system power pool charges. In 1998, the Kentucky PSC approved a settlement agreement providing for full recovery of costs associated with Rockport unit power purchases and transmission equalization payments. Previously, the Kentucky commission had limited recovery to the less expensive AEP power pool embedded cost rate rather than the more costly Rockport unit power agreement.

Markets. KPCo accounts for about 6% of AEP's internal electric sales. This AEP subsidiary serves about 167,000 retail customers in eastern Kentucky. The service territory's industrial base includes coal mining, primary metals, industrial chemicals, and petroleum refining. These industries are mature, slow-growing businesses, which are expected to result in sluggish electric sales growth over the long term.

The projected average annual rate of employment growth for the KPCo service area is 2.6% between 1996 and 2000, somewhat above the 1.4% for the nation as a whole. Yet, this largely reflects commercial sector development during this period. The underlying long-term growth path of the eastern Kentucky region is, almost certainly, slower than that of the U.S. in total. The regional core industries are petroleum refining, steel, industrial chemicals, and coal mining, all of which are stable or slow-growing in terms of employment changes, and this implies rather slow regional growth over the long term. It is worth noting that the chemicals, petroleum, and steel industries are expected to see significant increases in electric energy consumption over the near term. However, these expansions are not expected to have significant effects on the employment outlook.

The short-term economic outlook for the entire AEP service area continues to be relatively healthy. The number of residential and commercial customers, important measures of the regional economy, are both growing steadily. The

Service Area Economics*
(% chg.)

	1994	1995	1996	1997-1999¶	1997-2007¶
Manufacturing employment					
Service territory	3.3	1.8	(1.1)	0.4	0.0
ECAR region	2.9	2.0	(1.5)	(0.3)	(0.3)
National	1.1	0.8	(0.9)	0.0	(0.2)
Nonmanufacturing employment					
Service territory	3.4	2.5	2.1	1.7	1.5
ECAR region	3.1	2.1	1.7	1.7	1.5
National	3.1	2.6	1.8	2.2	1.8
Total employment					
Service territory	3.4	2.4	1.5	1.4	1.2
ECAR region	3.1	2.1	1.0	1.3	1.2
National	2.7	2.3	1.4	1.9	1.5
Population					
Service territory	0.9	0.8	0.6	0.5	0.5
ECAR region	0.5	0.5	0.5	0.5	0.5
National	1.0	0.9	0.9	0.9	0.8
Private housing starts					
Service territory§	14.8	(17.9)	0.0	0.7	0.2
ECAR region	10.6	(9.9)	(4.3)	0.5	0.0
National	13.0	(7.1)	(3.4)	1.9	1.4
Unemployment rate					
Service territory§	5.4	5.0	5.2	5.1	5.3
ECAR region	5.7	5.1	5.6	5.2	5.7
National	6.1	5.5	5.8	5.5	5.7
Real per capita income (1992 $)					
Service territory§	13,912	14,347	14,704	15,500	17,124
ECAR region	15,965	16,508	16,758	17,548	19,287
National	16,750	17,250	17,566	18,487	20,455

*Economic variables determined by the aggregation of metropolitan statistical areas provided by the company. ¶Employment, population, and housing start estimates represent compound annual growth rates for the period. Unemployment and real per capita income estimates represent forecasts for the last year in the period. §Data represent the largest metropolitan area(s) in the service territory. ECAR—East Central Area Reliability Coordination Agreement. *Source:* DRI/McGraw-Hill

March to March percent changes in the number of AEP customers are

- 1995-1996 1.1% residential, 2.1% commercial
- 1996-1997 1.1% residential, 2% commercial

The changes show a slight deceleration in both commercial and residential growth, suggesting that the upswing in the regional economy may have slowed.

The two-year outlook is for industrial kWh sales growth of 1.7% per year. The corresponding rates of increase in residential and commercial sales will likely be more brisk at about 2.1% and 2%, respectively.

Of the regions served by AEP, the most rapidly growing is Columbus, Ohio, and its satellite towns. Columbus, a banking, insurance, distribution, and government center, is one of the most rapidly growing cities in the northeastern U.S. AEP's Indiana and western Ohio service areas are largely dependent on the automotive industry, and, in recent years, this has implied fairly robust growth in that area as well. Yet, recent softness in the new car market could slow energy sales in this sector. Another growth center is western Virginia, including Roanoke and Lynchburg, where the manufacturing base is diverse and the labor market is favorable to investment. AEP's service region in the Ohio and Kanawha River Valleys—including Steubenville, Ohio; Wheeling, W.Va.; Huntington, W.Va.; Charleston, W.Va.; Ashland, Ky., and Portsmouth, Ohio—is heavily specialized in the production of primary metals and industrial chemicals. This implies a stable, or perhaps stagnant, long-term outlook.

The balance of the AEP service area encompasses the central Appalachian coal fields of southern West Virginia and southeastern Kentucky. The economy of this region is almost totally dependent on coal industry developments. The key in recent years have been productivity increases (for example, longwall mining) that have reduced the local demand for labor and, consequently, have tended to reduce the growth of regional employment and income. However, there have been recent expansions in the number of mines. Both the mechanization of the mines and the expanding number of mines have contributed to the growth of AEP's mine power sales.

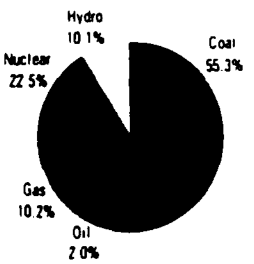
KPCo's long-term average annual growth rate for sales to retail customers is projected at 2% compared with the consolidated AEP sales growth rate of 1%. KPCo's long-term growth rate for residential sales is forecast at 2.1%, commercial 2.7%, and industrial 1.8%. For the first five months of 1997, retail energy sales decreased 2.4% compared with the year-ago period. Sales to industrial customers increased 1.5%, while lower demand as a result of warmer weather reduced

Market Segments

	1996p	1995	1994	1993	1992
Sales					
Total retail (GWh)	6,428	6,317	5,977	5,802	5,706
Residential (%)	34.1	34.7	33.9	34.0	33.1
Commercial (%)	17.9	18.0	17.9	17.8	17.4
Industrial (%)	47.9	47.2	48.0	48.0	49.4
Other (%)	0.2	0.2	0.2	0.2	0.2
Wholesale (GWh)	3,680	4,026	3,304	3,114	4,105
Total sales (GWh)	10,108	10,342	9,281	8,916	9,811
Revenue					
Total retail (mil. $)	258	264	250	243	249
Residential (%)	41.2	40.8	40.2	40.2	38.8
Commercial (%)	22.6	22.2	22.3	22.2	21.6
Industrial (%)	35.8	36.7	37.1	37.3	39.3
Other (%)	0.3	0.3	0.3	0.3	0.3
Wholesale (mil. $)	57	61	54	48	61
Total revenue (mil. $)	315	324	304	291	310
Annual sales growth (%)					
Residential	(0.0)	8.3	2.7	4.5	(0.6)
Commercial	1.5	5.8	3.7	4.3	0.2
Industrial	3.2	3.8	3.0	(1.2)	0.0
Total retail	1.8	5.7	3.0	1.7	(0.2)
Standard & Poor's retail avg	N.A.	3.1	2.6	3.5	0.3
Wholesale	(8.6)	21.8	6.1	(24.1)	40.1
Total sales growth	(2.3)	11.4	4.1	(9.1)	13.5
Retail customer growth	1.7	1.5	1.5	1.5	1.2

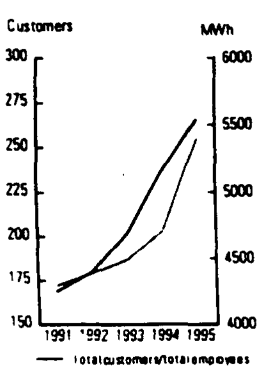
p—Preliminary data. N.A.—Not available. *Source:* UDI/McGraw-Hill

Industry Fuel Mix
1995



Source: Edison Electric Institute.

Industry Efficiency Measures



residential sales by 6.1%. Wholesale energy sales increased 15.6% because of higher energy sales to unaffiliated utilities by the AEP system power pool.

For the year ended Dec. 31, 1996, KPCo's retail electric sales increased by 1.8%, compared with the year-earlier period, while wholesale sales decreased by about 8.6%. Warmer weather in the second half of 1996 had a negative effect on sales growth, while a scheduled maintenance outage at Big Sandy Plant Unit 2 reduced KPCo's contribution to the AEP system power pool, resulting in lower wholesale sales. KPCo's internal load factor is estimated to continue in the 57% to 59% range.

Operations. The five major AEP operating subsidiaries participate in various contractual agreements, which define how each subsidiary shares in the cost and benefits associated with the system's generating plants, transmission capacity, and wholesale sales to nonaffiliated electric utilities. This sharing is based on each operating 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 major operating units during the preceding 12 months. In 1996, KPCo received from the AEP system $2 million for generating capacity, $3.3 million for transmission, and $7.6 million for offsystem AEP sales.

The AEP system is one of the strongest transmission systems in the world, with almost 22,000 circuit miles of transmission and 101,000 miles of distribution lines, connecting customers to AEP's 39 power plants. The AEP transmission system, with 119 high-voltage interconnections to 29 other utilities, provides an important link between the East Coast and the Midwest, and Canada and the Mid-South.

In addition to the AEP system, KPCo is directly interconnected with unaffiliated Kentucky Utilities Co., East Kentucky Power Cooperative, and the federal government's Tennessee Valley Authority.

AEP's compliance strategy for the Clean Air Act centers on the 1995 installation of scrubbers at the two-unit 2,600MW Gavin Plant owned by affiliate, OPCo. KPCo's clean air capital cost for Phase 2, ending Jan. 1, 2000, will require an additional $5 million of spending.

One of the important strengths of the AEP system is the performance of its electric generating equipment. In 1995, total energy costs of the five major operating subsidiaries on an unweighted basis averaged 2.77 cents per kWh compared with the region's average of 4 cents per kWh. AEP is strongly committed to achieving superior operational performance. For example, in 1996, AEP's system heat rate, which measures the amount of energy it takes to produce one kilowatt of electricity, was 9,749 British thermal units (Btu) per kWh—substantially better than the estimated industry average of 10,394Btu per kWh.

AEP derives about 85% of its electric generation from coal-fired units and about 12% from nuclear units, with variations largely related to nuclear refueling outages. A small amount of generation comes from hydroelectric generation and other sources. About 75% of AEP's coal requirements are obtained through long-term contracts, 11% from spot or short-term purchases, and 14% from coal reserves, which are owned or mined by AEP subsidiaries. The average cost of coal consumed during 1996 for AEP was $31.70 per ton, while KPCo paid $27.25 per ton. The total average price per million British thermal units (mmBtu) of coal burned in 1996 was $1.40 per mmBtu for AEP and $1.14 per mmBtu for KPCo.

The AEP system's all-time internal electric peak load was

Fuel And Power Supply

	1996p	1995	1994	1993	1992
*Generating capacity**					
Owned (MW)	23,060	23,765	23,932	23,626	23,934
Firm purchased (MW)	0	0	135	184	268
Peak demand (MW-winter)	19,981	20,106	19,388	18,237	17,649
Reserve margin (%)	15.4	18.2	24.1	30.6	37.1
Peak growth (%)	(0.6)	3.7	6.3	3.3	(0.5)
Annual load factor (%)	57.0	58.5	54.0	64.0	65.7
ECAR regional reserve margin (%-summer)	N.A.	N.A.	17.1	18.7	29.7
Generation by fuel source (%)					
Coal	69.0	71.8	60.2	60.0	66.8
Nuclear	10.2	10.0	0.0	0.0	0.0
Hydro	0.7	0.7	0.0	0.0	0.0
Purchased	25.6	23.4	39.8	40.0	33.2

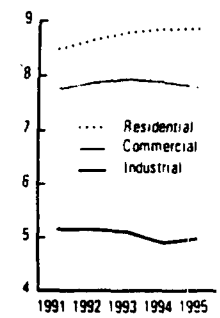
*Based on AEP System. p—Preliminary data. ECAR—East Central Area Reliability Coordination Agreement. *Source:* Edison Electric Institute.

Efficiency Statistics
Operating Efficiency (electric-retail)

	1996	1995	1994	1993	1992
Total customers/employee	233	219	196	189	183
Industry avg	N A	255	204	188	180
Total MWh/total employee	8.953	8,411	7,236	6,874	6,635
Industry avg	N A.	5,544	5,148	4,681	4,368
Total revenue/total kWh (cents)	4 01	4 17	4 19	4 18	4 36
Industry avg	N A	7 12	7 19	7 24	7 14

N A —Not available *Source:* UDI/McGraw-Hill

Industry Rates
(cents/kWh)



19,918MW, which occurred on Feb. 5, 1996. The net capacity to serve the AEP system load, including contractual arrangements, was 23,060MW at the time of the Feb. 5, 1996 internal peak demand for a reserve margin of 15.8%. Generating capability, including purchases of 1,450MW for KPCo, compared with a 1996 winter peak demand of 1,441MW (KPCo is a winter-peaking company). The resulting 0.6% reserve margin is not a major concern due to access to AEP system generation.

Currently, there are no plans for capacity additions on the AEP system until after 2000. Such equipment is likely to be short lead, simple-cycle or combined-cycle, gas-fired combustion turbines. KPCo's reserve generating margins are projected at adequate levels for the next five years based on the Rockport unit power purchase contract. Appalachian Power Co., along with Columbus Southern Power Co., are likely to be the next AEP subsidiaries to build peaking capacity sometime after 2000.

AEP's current resource plan indicates that the need for new coal-fired base load generation will not occur until after 2005. The size of any new coal-fired generation will most likely be significantly smaller than the 1,300MW units previously added to the AEP system in order to better match projected modest load growth.

KPCo participates with 26 other electric utilities operating in nine states in the East Central Reliability Coordination Agreement (ECAR), which was established to further the reliability of bulk power supply in the region through coordination of the planning and operation of ECAR members of their bulk power supply facilities. The ECAR members have established principles and procedures regarding matters affecting the reliability of the bulk power supply within the ECAR region.

The company's largest investment is its 1,060MW coal-fired Big Sandy plant with a net book value of $117.3 million, which represented 48.2% of KPCo's year-end 1996 common equity and 19.1% of capitalization. The Big Sandy plant represents 100% of KPCo's generating capability.

Competitiveness. AEP, via its five main operating subsidiaries, controls the largest electric utility system in the Midwest. AEP is one of the best-managed companies from an operating performance basis. High levels of efficiency and productivity have helped to keep energy prices competitive. The company is well known for its expertise in building and operating large, coal-fired units. With low electric rates, power to sell, and the most extensive transmission system in the country, AEP is a formidable competitor. Competitive gains are expected.

AEP is among the lowest-cost producers in the region; and, unlike the region's other low-cost producers, AEP actually has power to sell. If AEP wanted to add some peaking units and operate with a thinner reserve margin, it might have as much as 4,000MW to sell While, the company's largest customer, Ormet Aluminum Co. with a 527MW load, will be served by another supplier after 1999, AEP will continue to collect transmission fees from Ormet. The loss of this customer has no credit impact since it represents very low margin business.

With low electric rates, low production costs, available capacity for sale, and the most extensive transmission system in the country, the AEP system is a formidable competitor. The operating subsidiaries of AEP are expected to benefit if retail wheeling is adopted. In a fully competitive environment, AEP will probably focus on the high-cost northern Ohio utilities Centerior Energy Corp. and Ohio Edison Co., Michigan electrics Detroit Edison Co. and Consumers Power Co., as well as eastern markets that offer excellent opportunities in a competitive market. AEP may also have more cost-cutting opportunities than other regional electrics due to AEP's size and its corporate realignment, which creates generation group distinct from the energy transmission and distribution group. Acquisition of weaker regional electrics at favorable prices may also be possible.

In July 1995, AEP began a severance plan that eliminated about 1,200 jobs at 16 fossil-fuel power plants in five states. This is another significant step in AEP's comprehensive restructuring plan to improve performance and ensure competitiveness. The plan is one part of an overall restructuring program across AEP's seven-state service area to realign functionally into separate power generation and energy delivery groups. Job reductions began in early October 1995 and continued into 1996. Reductions affected power generation plants in West Virginia, Virginia, Ohio, Kentucky, and Indiana. AEP's fossil-fuel plants had employed about 5,200 workers before the reductions.

AEP fossil-fuel plants are now staffed to perform running maintenance; that is, maintenance performed while the generating units are producing energy, rather than being staffed for both running maintenance and scheduled outages.

In December 1995, AEP began offering a different kind of system sales transaction, called coal conversion. Under this concept, AEP contracts with a third party (usually a power marketer) to supply energy based on this new service from AEP power plants, generally in offpeak periods. The power marketer supplies the coal to the company's power plants. AEP converts the coal into electricity for the marketer, which then sells it to the ultimate buyer. This coal conversion was instrumental in increasing AEP's wholesale sales in 1996.

FINANCIAL PROFILE

Financial policy: Aggressive. Management's commitment to credit quality is overshadowed by efforts to enhance shareholder value, as evidenced by high debt leverage and a relatively high common dividend payout.

With limited domestic growth in AEP's core regulated domestic electric business, management will be more aggressive in nonregulated endeavors. For example, AEP management believes that future growth opportunities in various foreign markets, such as China, are more attractive than the mature domestic market.

Profitability. For the quarter ended March 31, 1997, KPCo's earnings increased 35% to $9.1 million, compared with year-earlier earnings of $6.8 million. Higher earnings largely reflected a decrease in fuel and maintenance expense. Revenues were flat as lower retail revenues were offset by increased wholesale sales to the AEP System Power Pool.

In 1996, KPCo's earnings decreased by $8.2 million because of warmer-than-normal weather conditions that reduced demand and higher operations and maintenance and purchased power expenses due to the maintenance outage at Big Sandy Plant Unit 2. Going forward, earnings will be heavily dependent on retail sales growth, and management's ability to control costs. Forecast retail sales growth of about 1.4% annually should permit modest earnings improvement. However, heavy external funding requirements will result in higher interest expense levels, which will

Energy Costs And Rates (1996)
(cents/kWh)

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Kentucky Power Co.	**1.16**	**1.46**	**0.29**	**2.57**	**2.03**	**2.87**	**4.91**	**5.17**	**3.24**
Appalachian Power Co.	1.61	2.02	0.85	2.17	2.60	3.88	5.68	5.14	3.68
Cincinnati Gas & Electric Co.	1.51	1.92	1.83	1.77	3.51	4.47	7.73	6.83	4.62
Cleveland Electric Illuminating Co.	1.58	2.69	3.29	6.39	6.01	7.43	11.04	9.47	6.54
Columbus Southern Power Co.	1.45	2.07	1.93	2.78	3.59	5.00	7.88	6.41	4.79
Consumers Energy Co.	1.53	2.57	1.84	4.19	4.31	5.99	7.52	6.96	5.38
Dayton Power & Light Co.	1.48	1.90	2.08	2.01	3.74	4.75	8.67	6.94	5.09
Duquesne Light Co.	1.47	2.39	2.11	1.97	4.31	6.10	12.31	8.42	5.94
Indiana Michigan Power Co.	0.88	1.84	1.25	2.14	2.91	3.48	6.76	5.96	4.53
Indianapolis Power & Light Co.	1.21	1.67	1.03	7.41	2.79	3.80	5.68	5.92	4.24
Kentucky Utilities Co.	1.34	1.74	0.82	2.14	2.48	3.31	4.64	4.46	3.48
Louisville Gas & Electric Co.	1.16	1.75	1.09	3.01	2.85	3.53	5.90	5.51	3.66
Monongahela Power Co.	1.39	2.16	1.01	3.54	3.29	4.26	7.45	6.33	4.15
Northern Indiana Public Service Co.	1.68	2.40	1.71	1.73	3.76	4.94	9.89	8.55	4.51
Ohio Edison Co.	1.40	2.26	2.06	2.73	4.20	5.22	10.57	9.47	6.22
Ohio Power Co.	1.54	1.97	0.83	1.71	2.71	3.47	6.48	5.46	3.19
Potomac Edison Co.	1.40	2.13	1.07	3.24	3.22	4.19	7.24	6.56	3.66
PSI Energy Inc.	1.46	1.81	0.80	1.97	2.54	3.46	5.91	4.67	3.46
Southern Indiana Gas & Electric Co.	1.50	2.14	1.24	1.67	3.22	3.85	6.65	5.45	3.62
Toledo Edison Co.	1.43	2.54	3.53	2.35	5.93	6.96	10.99	10.51	6.09
West Penn Power Co.	1.41	2.07	1.24	3.35	3.32	4.27	6.89	5.93	4.54
ECAR region average	**1.42**	**2.07**	**1.50**	**2.91**	**3.44**	**4.49**	**7.51**	**6.80**	**4.45**
Standard & Poor's average	**1.42**	**2.21**	**1.80**	**3.97**	**4.00**	**5.34**	**8.87**	**7.79**	**4.98**

ECAR—East Central Area Reliability Coordination Agreement. *Source:* UDI/McGraw-Hill

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.lace downward pressure on earnings protection measures Adjusted pretax interest coverage is projected to be in the 2 15 times (x) to 2 45x range during the next five years, compared to the current level of 2.37x. The company's 1995 issue of $40 million junior subordinated deferrable interest debentures was given preferred equity treatment, which will help maintain adjusted interest coverage.

Cash flow protection. Cash construction expenditures for 1997 to 2001 are budgeted at about $275 million, which is a relatively high level given no new major plant construction. Depreciation and amortization over the same period is forecast at about $147 million. Over the next five years, capital spending will average 9.7% of total capitalization.

Prospectively, net cash flow will cover only a relatively small 45% of planned capital spending through ?001. Funds from operations .nterest coverage will be under downward pressure as a consequence of heavy external funding needs and higher projected debt levels with resulting greater interest expense. Thus, projected adjusted funds from operations interest coverage is expected to range from 2.75x to 3x, compared to the current level of 3.16x at March 31, 1997. In addition, funds from operations to average adjusted debt should stay weak ranging from 13% to 15% during the next five years, compared to the current level of 13.7%.

Capital structure. Credit ratings are predicated on maintenance of the current capital structure, which will require meaningful equity infusions from parent, AEP, during the next five years. Standard & Poor's believes that KPCo will not be able to materially reduce adjusted debt leverage over the next five years given external funding needs. However, preferred equity treatment for the April 1995 junior subordinated deferrable interest debenture issue has resulted in lower leverage levels for analytical purposes.

Asset quality is adequate. Regulatory assets at year-end 1996 were a modest $4.5 million, excluding $84 2 million due from customers for future federal income taxes: Regulatory assets are expected to be recovered in future periods through the ratemaking process

Financial flexibility. KPCo has adequate financing flexibility given its membership in the AEP family. At Dec. 31, 1996, unused short-term lines of credit were shared with AEP system companies, of which $409 million was available; however, provisions of PUHCA limit short-term borrowings to $150 million. At year-end 1996, KPCo's outstanding short-term borrowings totaled about $52 million. In addition, the utility has guaranteed $10.3 million of loans related to customer purchase of efficient electrical equipment. Periodic reductions of outstanding short-term debt are made through issuance of long-term debt, and equity capital contributions by AEP. In 1996, AEP made a cash capital contribution of $30 million.

Financing Flexibility

Common equity characteristics as of March 31

Ticker symbol
Stock price ($)
PE ratio (x)
Dividend yield (%)
Market to book (%)
Dividend to book (%)

Debt characteristics at fiscal year ended 1

Secured debt (%)
Unsecured debt (%)
Subordinated debt (%)

Fixed-rate debt (%)
Variable-rate debt (%)

Avg. life of long-term debt (years)
Embedded cost of long-term debt (%)
Debt maturing in five years (mil $)

Short-term Financing
As Of Dec. 31, 1996

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	0.0	17.8			
Bank lines					
Contracted committed lines	409.0	33.8	N.A.	Yes	N.A.
Avg cost of short-term debt (%)	6.2				

MAC—Material adverse change N.A.—Not available

Financial Statistics—Kentucky Power Co.

	1997*	1996	—Year ended Dec. 31— 1995	1994	1993
Income statement (mil. $)					
Gross revenues	323.3	323.3	328.1	307.4	294.3
Operating expenses (excl. DD&A)	246.8	251.1	250.4	235.7	231.8
Depreciation and amortization	25.4	25.1	24.4	23.0	22.3
Pretax operating income	51.1	47.1	53.3	48.7	40.2
Gross interest expense	21.1	20.3	21.6	21.2	21.0
Pretax income	29.1	25.6	29.0	27.5	19.7
AFUDC and deferrals	0.0	0.0	0.4	0.5	0.3
Income taxes	7.1	5.1	3.9	2.2	1.6
Net income from continuing operations	22.0	20.5	25.1	25.3	18.0
Earnings protection					
Pretax interest coverage (x)	2.38	2.26	2.32	2.27	1.92
Adjusted pretax interest coverage (x)	2.37	2.26	2.32	2.26	1.91
Preferred dividend coverage (x)	1.91	1.80	1.97	2.27	1.92
EBITDA interest coverage (x)	3.59	3.50	3.45	3.36	2.98
AFUDC and deferred income/earnings (%)	0.0	0.0	1.5	1.9	1.5
Return on common equity (nominal) (%)	7.6	7.3	10.5	12.5	9.3
Common dividend payout (%)	134.7	143.0	101.8	84.7	125.8
Annual O&M growth (%)	(3.7)	8.2	2.7	5.7	N.A.
Annual expense growth (excl. DD&A) (%)	(1.7)	0.3	6.2	1.7	N.A.
O&M/revenues (%)	23.6	24.5	22.3	23.2	22.9
Total operating expenses (excl. DD&A)/revenues (%)	76.3	77.7	76.3	76.7	78.8
Balance sheet (mil. $)					
Cash and equivalents	3.5	1.1	1.0	0.9	0.9
Gross plant	958.7	951.6	879.7	851.9	807.4
Net plant	672.0	665.0	609.1	591.9	558.8
Total assets	842.4	833.6	772.2	739.8	670.4
Short-term debt	59.2	54.7	58.8	57.0	39.7
Long-term debt	253.2	276.0	272.5	261.7	260.1
Preferred stock	40.0	40.0	40.0	0.0	0.0
Common equity	245.7	243.3	220.6	208.4	194.5
Total capitalization	598.1	614.0	591.9	527.0	494.3
Total off-balance-sheet obligations	0.9	0.9	1.2	2.1	2.1
Balance sheet ratios (%)					
Short-term debt/total capital	9.9	8.9	9.9	10.8	8.0
Long-term debt/total capital	42.3	45.0	46.0	49.6	52.6
Preferred stock/total capital	6.7	6.5	6.8	0.0	0.0
Common equity/total capital	41.1	39.6	37.3	39.5	39.3
Adjusted total debt/total capital	52.3	53.9	56.1	60.6	60.8
Debt/EBITDA (x)	4.1	4.7	4.4	4.5	4.8
Cash flow (mil. $)					
Net income	22.0	20.5	26.5	25.3	18.0
Depreciation	25.5	25.2	24.5	23.1	22.4
Deferred taxes and ITC	1.1	0.5	(3.9)	(2.7)	(1.8)
AFUDC and deferrals	0.0	0.0	(0.4)	(0.5)	(0.3)
Other FFO adjustments	(4.7)	(7.4)	1.2	(0.2)	(4.4)
Funds from operations (FFO)	43.8	38.7	48.0	45.0	34.0
Preferred dividends	(3.5)	(3.5)	(2.6)	0.0	0.0
Common dividends	(24.9)	(24.3)	(22.9)	(21.4)	(22.7)
Net cash flow (NCF)	15.5	11.0	22.4	23.6	11.3
Working capital changes	6.4	9.8	(3.9)	0.9	2.7
Capital expenditures (capex)	(80.7)	(75.8)	(38.9)	(52.6)	(35.0)
Discretionary cash flow	(58.9)	(55.0)	(20.4)	(28.2)	(21.0)
Cash flow adequacy					
Capex/avg. total capital (%)	13.3	12.6	7.0	10.3	7.1
NCF/capex (%)	19.2	14.5	57.6	44.8	32.2
FFO/avg. total debt (%)	13.6	11.7	14.8	14.5	11.3
Adjusted FFO/avg. total debt (%)	13.7	11.8	14.8	14.6	11.4
FFO interest coverage (x)	3.16	3.09	3.30	3.09	2.52
Adjusted FFO interest coverage (x)	3.17	3.11	3.31	3.09	2.53

*For 12 months ended March 31 (unaudited). N.A.—Not available. AFUDC—Allowance for funds used during construction. O&M—Operations and maintenance. ITC—Investment tax credits. DD&A—Depreciation, depletion, and amortization. EBITDA—Earnings before interest, taxes, depreciation, and amortization.

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Notes

Notes

UTILITY CREDIT REPORT

STANDARD & POOR'S
Utilities Rating Service

KENTUCKY POWER CO.

CORPORATE CREDIT RATING	BBB+
OUTLOOK	STABLE

Analyst: Steve Zimmerman, New York (1) 212-208-1658; Company contact: John S. Bilacic (614) 223-2847

OUTSTANDING RATINGS

Senior secured debt	BBB+
Subordinated	BBB

OUTLOOK: STABLE
ELECTRIC BUSINESS POSITION: Somewhat above average (2)

DEBT RATING HISTORY

SENIOR DEBT	Nov. 15, 1988	BBB+
	Jan. 23, 1985	BBB
	May 16, 1983	BBB+
	Oct. 22, 1976	A
	Jan. 7, 1972	BBB

RATIONALE

Kentucky Power Co.'s (KPCo) creditworthiness is enhanced by its membership in the American Electric Power Co. (AEP) system. The company's ratings largely reflect AEP's somewhat above average business position evaluation and consolidated financial profile. System internal funds generation and cash interest coverage are expected to remain adequate, although debt leverage continues to be aggressive. AEP challenges include increasing wholesale profitability, a cyclical industrial load, strict state rate regulation, and acid rain exposure. In late 1988, the Kentucky Power Service Commission (KPSC) approved a settlement agreement providing for full recovery of costs associated with Rockport unit power purchases and transmission equalization payments. Previously, the Kentucky commission had limited recovery to the less expensive AEP power pool embedded cost rate rather than the more costly Rockport unit power agreement. Still, KPCo's interest coverage and capitalization ratios after adjusting for capacity payments associated with long-term contracted Rockport power purchases are weak but are supported by the system's stronger financial condition. For the next five years, projected KPCo spending will require significant external funding, which will pressure financials. Common equity infusions from parent AEP will be needed to maintain a balanced capital structure.

OUTLOOK

Strong consolidated AEP operations provide ratings stability and support for maintenance of KPCo's credit quality. Significant capital spending relative to KPCo's size and cash flow generation capability will restrain credit improvement for this AEP subsidiary. Acid rain spending, purchased power, and lackluster projected retail sales growth add risk but are largely reflected in ratings.

Financial summary (Mil. $)	1996*	1995	1994	1993	1992
Gross revenues	331.4	328.1	307.4	294.3	313.2
Net income from continuing operations	27.2	26.5	25.3	18.0	26.5
Funds from operations (FFO)	50.1	48.0	45.0	34.0	48.6
Net cash flow	23.3	22.4	23.6	11.3	25.3
Capital expenditures	39.9	38.9	52.6	35.0	31.3
Total capital	582.6	551.9	527.0	494.3	474.6
Adjusted ratios					
Pretax interest coverage (x)	2.56	2.40	2.26	1.91	2.23
Total debt/total capital (%)	53.5	52.9	60.6	60.8	58.0
FFO interest coverage (x)	3.64	3.31	3.09	2.53	3.03
FFO/avg. total debt (%)	16.7	15.8	14.6	11.9	16.9

*For 12 months ended March 31 (unaudited).

Operating summary	1995p	1994	1993	1992	1991
Growth (%)					
Retail (MWh)	5.7	3.0	1.7	(0.2)	3.4
Retail (customers)	2.2	1.5	1.5	1.2	1.0
Capacity (MW)	N.A.	24,067	23,810	24,202	24,120
Reserve margin (%)	N.A.	24.1	30.6	37.1	36.0
Rates (cents/kWh)					
Residential	4.91	4.97	4.94	5.12	5.13
Commercial	5.16	5.21	5.21	5.41	5.44
Industrial	3.24	3.24	3.25	3.47	3.54

p—Preliminary data. MW—Megawatts. MWh—Megawatt-hours. kWh—Kilowatt-hours. N.A.—Not available.

KENTUCKY POWER CO.

RECENT DEVELOPMENTS

July 1996. A new corporation, AEP Power Marketing, filed an application with the Federal Energy Regulatory Commission (FERC) seeking power marketing status. The new corporation is a subsidiary of AEP. Power marketing status will allow AEP Power Marketing to purchase electricity and resell it to utilities and other wholesale energy users at market-based rates.

July 1996. AEP reported second-quarter 1996 earnings of $112.7 million, a 16.8% increase from the $96.5 million earned in 1995. Earnings per share for the quarter were 60 cents, an increase of 15.4% from the 52 cents reported for the same period in 1995. For the 12 months ended June 30, 1996, earnings increased 18.6% to $578.3 million from $487.6 million in the year earlier period. On the same basis, earnings per share rose to $3.10 from $2.63.

July 1996. AEP announced that a number of rural electric cooperatives and municipal groups have joined the Midwest independent system operator (ISO) and regional power exchange. Some of the new members include Big Rivers Electric Corp., East Kentucky Power Cooperatives, Hoosier Energy, The Indiana Municipal Power Agency, and Michigan Public Power.

June 1996. Andrew P. Varley was named senior vice president of energy pricing and regulatory services for AEP. Mr. Varley was vice president of rates, and he chairs AEP's Public Policy Task Force. This restructuring of AEP's rates department as energy pricing and regulatory services reflects the transition AEP is making from a regulated to a competitive marketplace.

April 1996. The FERC issued final rulings regarding open access transmission and stranded cost recovery in the wholesale market. The company adopted an open access transmission tariff in 1995 under the provisions of a proposed FERC rule. These final FERC rules are not expected to impact adversely the company's credit quality.

February 1996. Six Midwestern utilities have agreed to pursue the development of an independent organization responsible for bulk power transmission in the Midwest. The utilities signing the memorandum of understanding are AEP, Centerior Energy Corp., Cinergy Corp., DTE Energy Co., NIPSCO Industries Inc., and Wisconsin Energy Corp.

MAJOR STRENGTHS AND RISKS

Major strengths:

- AEP family membership.
- Low-cost producer with low rates.
- No nuclear exposure.

Major risks:

- Below-average sales growth prospects compared to AEP consolidated.
- System settlements will be less favorable given Ohio Power Co.'s (OPCo) investment in scrubbers for the Gavin plant.
- Although Kentucky rate regulation has been favorable for most electrics, AEP has not been treated as well.
- Industrialized service territory with above-average unemployment.

CORPORATE STRUCTURE

KPCo is the smallest of the five major operating subsidiaries of the AEP system. AEP is a registered public utility holding company that owns directly or indirectly all of the common stock of its operating electric utility subsidiaries. The service area of AEP's electric subsidiaries contains almost seven million people and covers

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qualifying cogeneration facilities, and other power projects. Currently, AEP Resources has no interest in any power projects. However, a subsidiary of AEP Resources is in preliminary development of a number of projects, including the development of two 1,300 megawatt (MW) generating stations in China. In addition, this subsidiary is negotiating a joint venture with two Chinese partners to develop and own two 125MW coal-fired units in Henan Province, China. AEP Resources has entered into a strategic alliance with Cogentrix Energy Inc. and Zurn Industries Inc. to develop, own, and operate, industrial power projects in the U.S. and Canada. AEP Resources also is studying investment opportunities in new and existing generation equipment in Australia, Mexico, and India.

AEP has received approval from the SEC under Public Utility Holding Company Act of 1935 (PUHCA) to finance up to $300 million for investment in exempt wholesale generators and foreign utility companies. AEP also has requested approval to finance up to 50% of its consolidated retained earnings (over $700 million) in exempt wholesale generators and foreign utility companies. In addition, AEP has requested authority from the SEC under the PUHCA to invest up to $100 million in subsidiaries engaged in the marketing of energy commodities, including electricity and gas.

SERVICE AREA KPCo accounts for about 6% of AEP's internal electric sales. This AEP subsidiary serves about 163,000 retail customers in eastern Kentucky. The service territory's industrial base includes coal mining, primary metals, industrial chemicals, and petroleum refining. These industries are mature, slow-growing businesses, which are expected to result in sluggish electric sales growth over the long term.

Service area economics*
(% chg.)

	1993	1994	1995	1996-1998¶	1996-2006¶
Manufacturing employment					
Service territory	2.6	3.3	1.8	0.0	(0.1)
ECAR region	0.8	2.9	2.0	(0.8)	(0.5)
National	0.0	1.1	0.8	(0.3)	(0.3)
Nonmanufacturing employment					
Service territory	2.6	3.4	2.5	1.7	1.5
ECAR region	2.2	3.1	2.1	1.7	1.5
National	2.3	3.1	2.6	2.0	1.8
Total employment					
Service territory	2.6	3.4	2.4	1.4	1.3
ECAR region	1.9	3.1	2.1	1.2	1.1
National	1.9	2.7	2.3	1.7	1.5
Population					
Service territory	1.0	0.9	0.8	0.6	0.5
ECAR region	0.6	0.5	0.5	0.5	0.5
National	1.1	1.0	0.9	0.9	0.9
Private housing starts					
Service territory§	8.1	14.8	(17.9)	(1.1)	0.2
ECAR region	3.0	10.6	(9.9)	(2.7)	(0.3)
National	6.5	13.0	(7.1)	(1.4)	1.0
Unemployment rate					
Service territory§	8.2	5.4	5.0	5.3	5.4
ECAR region	6.6	5.7	5.1	5.5	5.8
National	6.8	6.1	5.5	5.7	5.8
Real per capita income (1987 $)					
Service territory§	13,515	13,912	14,347	15,209	16,864
ECAR region	15,370	15,965	16,508	17,243	19,003
National	16,393	16,750	17,250	18,140	20,140

*Economic variables determined by the aggregation of metropolitan statistical areas provided by the company. ¶Employment, population, and housing start estimates represent compound annual growth rates for the period. Unemployment and real per capita income estimates represent forecasts for the last year in the period. §Data represent the largest metropolitan area(s) in the service territory. ECAR—East Central Area Reliability Coordination Agreement. *Source:* DRI/McGraw-Hill.

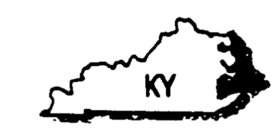
portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The total AEP service territory covers 45,400 square miles. The generating and transmission facilities of AEP's subsidiaries are interconnected, and their operations are coordinated as a single integrated electric utility system. Substantially all of the operating revenues of the AEP system are derived from providing electric service.

In June 1995, AEP realigned its organization structure to create a distinct power generation group and an energy transmission and distribution group. At this time, however, there are no changes in asset ownership or formal legal entities. In addition, AEP plans to offer an extensive array of services outside its traditional service territory and regulated business lines. Performance improvements also are planned, such as increasing the availability of AEP generating units, reducing fuel costs, increasing efficiencies in purchasing and materials management, implementing an Activity Based Management System, and investing in new technology and employee development. Furthermore, AEP plans to gradually phase out operating company identification. Management intends to enhance brand loyalty to the AEP name because of increasing competition and deregulation.

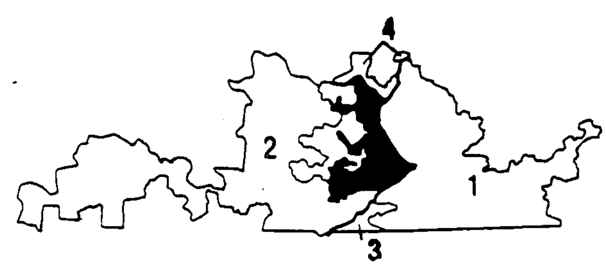
On a consolidated basis, AEP's overall creditworthiness is viewed as a weak 'A-', strong 'BBB+', given a somewhat above average business position evaluation. Thus, the senior secured debt of the operating subsidiaries will tend to be in the 'BBB+' to 'A-' range.

AEP continues to study nonregulated business opportunities, particularly those that relate to the company's electric expertise. Such endeavors are conducted through AEP Energy Services Inc. and AEP Resources Inc. AEP Energy offers various consulting services, both domestically and internationally, that relate to the company's electric expertise. AEP Resources' primary business is development and investment in exempt wholesale generators, foreign utility companies,

KENTUCKY POWER CO.



Neighboring utilities
1. **Appalachian Power Co.**
2. **Kentucky Utilities Co.**
3. **Old Dominion Power Co.**
4. **Ohio Power Co.**



Source: Salomon Brothers Inc.

CMH 1996

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Industries served
(1994)

Industry type	Sales (%)	Revenue (%)
Coal mining	38.9	47.5
Petroleum refining	31.0	24.6
Primary metal	17.0	15.2
Chemicals	9.6	7.9
Total (GWh/mil. $)	2,870	93

GWh—Gigawatt-hours. *Source:* Edison Electric Institute.

The projected average annual rate of employment growth for the KPCo service area is 2.2% between 1995 and 1998, somewhat above the 1.4% foreseen for the nation as a whole. Yet, this largely reflects commercial sector development during this period. The underlying long-term growth path of the eastern Kentucky region is, almost certainly, slower than that of the U.S. in total. The regional core industries are petroleum refining, steel, industrial chemicals, and coal mining, all of which are stable or slow-growing in terms of employment changes, and this implies rather slow regional growth over the long term. It is worth noting that the chemicals, petroleum, and steel industries are expected to see significant increases in electric energy consumption over the near term; however, these expansions are not expected to have significant effects on the employment outlook.

The short-term economic outlook for the entire AEP service area is relatively good. The number of residential and commercial customers—important measures of the regional economy—are both growing steadily. The April 1995 to April 1996 percent changes in the number of AEP customers are:

- 1994-1995: 1.3% residential, 2.2% commercial
- 1995-1996: 1.1% residential, 2.2% commercial

Still, last year at this time, growth in both categories was accelerating, while the information above shows an even pace in commercial growth and a slight deceleration in residential. This suggests that the recent upswing in the regional economy may have reached its crest.

The year-ahead outlook is for industrial sales growth of 1.5% to 2.0% per year. This is up from last year's industrial outlook, partly due to recently demonstrated strength in the regional manufacturing economy, and partly due to a rapid expansion at a new steel mill being served in Indiana. The corresponding rates of increase in residential and commercial sales will likely be more brisk, at around 2.0% and 3.0%, respectively.

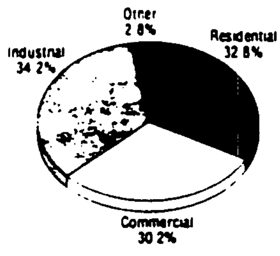
Of the regions served by AEP, the most rapidly growing is Columbus, Ohio and its satellite towns. Columbus, a banking, insurance, distribution and government center, is one of the most rapidly growing cities in the northeastern U.S. AEP's Indiana and western Ohio service areas are largely dependent on the automotive industry, and, in recent years, this has implied fairly robust growth in that area as well. Another growth center is western Virginia, including Roanoke and Lynchburg, where the manufacturing base is diverse and the labor market is favorable to investment. AEP's service region in the Ohio and Kanawha River valleys—including Steubenville, Ohio; Wheeling, W.V.; Huntington, W.V.; Charleston, W.V.; Ashland, Ky.; and Portsmouth, Ohio—is heavily specialized in the production of primary metals and industrial chemicals. This implies a stable, or perhaps stagnant, long-term outlook.

The balance of the AEP service area encompasses the central Appalachian coal fields of southern West Virginia and southeastern Kentucky. The economy of this region is almost totally dependent on coal industry developments. The key in recent years has been productivity increases (for example, in longwall mining), which have reduced the local demand for labor and, consequently, have tended to reduce the growth of regional employment and income. On the other hand, there have been recent expansions in the number of mines. Both the mechanization of the mines and the expanding number of mines have contributed to the growth of AEP mine power sales.

SALES

KPCo's long-term average annual growth rate for sales to retail customers is projected at 2.0% compared with the consolidated AEP sales growth rate of 1.8%. KPCo's long-term growth rate for residential sales is forecasted at 1.7%, commercial 2.0%, and industrial 2.3%. For the first six months of 1996, retail energy sales increased 5.7% compared with the year-ago period. Sales to industrial customers expanded 2.0%, reflecting strength in local industrial output, while favorable weather increased residential sales by 10.1%. Wholesale energy sales increased 17.6% because of higher energy sales to unaffiliated utilities by the AEP system power pool.

Industry Retail Sales (MWh)
1994



Source: Edison Electric Institute.

For the year ended Dec. 31, 1995, KPCo's retail electric sales increased by 5.7%, compared with the year-earlier period, while wholesale sales increased by about 21.8%. Retail sales were helped in 1995 by favorable weather and stronger industrial demand. For example, KPCo's 1995 residential sales increased about 8.2%, while commercial volume gained 5.8% and industrial sales expanded 3.8% compared to 1994 sales. Wholesale energy sales advanced almost 22%, reflecting increased availability of generating equipment and increased weather related demand to affiliated AEP system power pool members. KPCo's internal load factor is estimated to continue in the 57% to 59% range.

COMPETITIVE POSITION

AEP, via its five main operating subsidiaries, controls the largest electric utility system in the Midwest. AEP is among the lowest-cost producers in the region, and, unlike the region's other low-cost producers, AEP actually has power to sell. If AEP wanted to add some peaking units and operate with a thinner reserve margin, it might have as much as 4,000MW to sell plus another 800MW if Ohio's aluminum industry closed.

With low electric rates, low production costs, available capacity for sale, and the most extensive transmission system in the country, the AEP system is a formidable competitor. AEP's operating subsidiaries are expected to benefit if retail wheeling

Market segments

	1995p	1994	1993	1992	1991
Sales					
Total retail (GWh)	6,317	5,977	5,802	5,706	5,717
Residential (%)	34.7	33.9	34.0	33.1	33.2
Commercial (%)	18.0	17.9	17.8	17.4	17.3
Industrial (%)	47.2	48.0	48.0	49.4	49.4
Other (%)	0.2	0.2	0.2	0.2	0.2
Wholesale (GWh)	4,025	3,304	3,114	4,105	2,930
Total sales (GWh)	10,342	9,281	8,916	9,811	8,647
Revenue					
Total retail (mil. $)	268	250	243	249	252
Residential (%)	40.2	40.2	40.2	38.8	38.7
Commercial (%)	21.9	22.3	22.2	21.6	21.4
Industrial (%)	36.1	37.1	37.3	39.3	39.6
Other (%)	1.8	0.3	0.3	0.3	0.3
Wholesale (mil. $)	61	54	48	61	52
Total revenue (mil. $)	328	304	291	310	304
Annual sales growth (%)					
Residential	8.3	2.7	4.5	(0.6)	10.4
Commercial	5.8	3.7	4.3	0.2	7.5
Industrial	3.8	3.0	(1.2)	(0.0)	(2.1)
Total retail	5.7	3.0	1.7	(0.2)	3.4
Standard & Poor's retail avg.	0.0	2.6	3.6	[illegible]	2.0
Wholesale	21.8	6.1	(24.1)	40.1	(37.4)
Total sales growth	11.4	4.1	(9.1)	13.5	(15.3)
Retail customer growth	2.2	1.5	1.5	1.2	1.0

p—Preliminary data. GWh—Gigawatt-hours. *Source:* UDI/McGraw-Hill.

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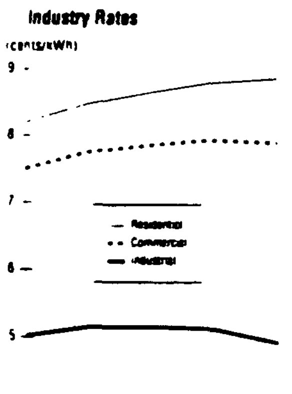

is adopted. In a fully competitive environment, AEP will probably focus on the high-cost northern Ohio utilities Centerior Energy Co. and Ohio Edison Co., Michigan electrics Detroit Edison Co. and Consumers Power Co., as well as eastern markets, which offer excellent opportunity in a competitive market. AEP also may have more cost-cutting opportunity than other regional electrics due to its size and corporate realignment, which creates a distinct generation group and an energy transmission and distribution group. Acquisition of weaker regional electrics at favorable prices also may be possible.

In July 1995, AEP began a severance plan that eliminated about 1,200 jobs at 16 fossil-fuel power plants in five states. This is another significant step in AEP's comprehensive restructuring plan to improve performance and ensure competitiveness. The plan is one part of an overall restructuring program across AEP's seven-state service area to realign functionally into separate power generation and energy delivery groups. Job reductions began in early October 1995 and continued into 1996. Reductions affected power generation plants in West Virginia, Virginia, Ohio, Kentucky, and Indiana. AEP's fossil-fuel plants had employed about 5,200 workers before the reductions.

AEP fossil-fuel plants are now staffed to perform running maintenance; that is, maintenance performed while the generating units are producing energy, rather than being staffed for both running maintenance and scheduled outages.

FUEL AND POWER SUPPLY

AEP derives about 85% of its electric generation from coal-fired units and about 12% from nuclear units, with variations largely related to nuclear refueling outages. A small amount of generation comes from hydroelectric generation and other sources. About 75% of AEP's coal requirements are obtained through long-term contracts, 11% from spot or short-term purchases, and 14% from coal

Energy costs and rates (1994)
(cents/kWh)

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Kentucky Power Co.	**1.15**	**1.58**	**0.33**	**2.44**	**2.13**	**3.[illegible]**	**4.87**	**5.21**	**3.24**
Appalachian Power Co.	1.72	2.10	0.79	2.74	2.84	4.05	5.78	5.24	3.78
Cincinnati Gas & Electric Co.	1.55	2.03	1.78	1.87	3.71	5.22	7.71	6.86	4.67
Cleveland Electric Illuminating Co.	1.55	2.61	3.42	6.15	6.04	7.40	10.79	9.38	6.37
Columbus Southern Power Co.	1.54	2.09	1.65	3.70	3.73	5.12	7.91	6.52	4.87
Consumers Power Co.	1.57	2.58	1.67	4.46	4.34	5.96	7.37	7.02	5.42
Dayton Power & Light Co.	1.52	2.01	2.09	2.38	4.00	5.13	8.75	7.11	5.21
Detroit Edison Co.	1.79	2.46	2.38	2.40	4.47	5.90	9.34	8.65	5.45
Duquesne Light Co.	1.51	2.28	1.98	3.47	4.23	6.01	12.36	8.50	5.93
Indiana Michigan Power Co.	0.96	2.12	1.46	2.28	3.31	3.92	6.78	5.98	4.52
Indianapolis Power & Light Co.	1.25	1.72	0.99	9.23	2.81	3.79	5.66	5.86	4.23
Kentucky Utilities Co.	1.17	1.52	0.70	2.00	2.19	3.00	4.54	4.35	3.39
Louisville Gas & Electric Co.	1.23	1.80	1.32	1.68	3.05	3.83	6.06	5.56	3.76
Monongahela Power Co.	1.50	2.12	0.93	4.27	3.38	4.40	7.14	6.29	4.09
Northern Indiana Public Service Co.	1.79	2.52	1.76	1.84	4.01	5.24	10.17	8.71	4.71
Ohio Edison Co.	1.47	2.43	2.78	2.45	5.00	6.22	10.64	9.54	6.27
Ohio Power Co.	1.74	2.12	0.69	2.11	2.76	3.50	6.23	5.37	3.15
Potomac Edison Co.	1.51	2.05	0.96	3.67	3.26	4.26	7.02	6.36	3.65
PSI Energy Inc.	1.52	1.87	0.83	2.06	2.66	3.60	5.74	4.52	3.36
Southern Indiana Gas & Electric Co.	1.59	2.21	1.13	1.66	3.24	3.92	6.67	5.68	3.95
Toledo Edison Co.	1.43	2.77	3.75	2.96	6.28	7.27	11.04	10.59	6.12
West Penn Power Co.	1.53	2.10	1.09	4.03	3.42	4.42	6.56	5.72	4.45
ECAR region average	**1.53**	**2.18**	**1.80**	**3.25**	**3.[illegible]**	**4.83**	**7.[illegible]**	7.13	4.55
Standard & Poor's average	**1.48**	**2.29**	**1.90**	**4.31**	**4.22**	**5.[illegible]**	**8.34**	7.85	5.04

ECAR—East Central Area Reliability Coordination Agreement. kWh—Kilowatt-hour. *Source:* UDI/McGraw-Hill.

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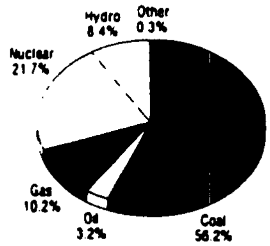
Industry Fuel Mix
1994



Source. Edison Electric Institute

reserves, which are owned or mined by AEP subsidiaries. The average cost of coal consumed during 1995 for AEP was $32.52 per ton, while KPCo paid $26.91 per ton. The total average price per million British thermal units (mmBtu) of coal burned in 1994 was $1.45 per mmBtu for AEP and $1.15 per mmBtu for KPCo.

The AEP system's all-time internal electric peak load was 19,918MW, which occurred on Feb. 5, 1996. The net capacity to serve the AEP system load, including contractual arrangements, was 23,060MW at the time of the Feb. 5, 1996 internal peak demand for a reserve margin of 15.8%. Generating capability, including purchases of 1,450MW for KPCo, compared with a 1996 winter peak demand of 1,441MW (KPCo is a winter-peaking company). The resulting 0.6% reserve margin is not a major concern due to access to AEP system generation.

At the present time, there are no plans for capacity additions on the AEP system until after the year 2000. Such equipment is likely to be short lead, simple cycle, gas-fired combustion turbines. KPCo's reserve generating margins are projected at adequate levels for the next five years based on the Rockport unit power purchase contract. Appalachian Power Co., along with Columbus Southern Power Co., are likely to be the next AEP subsidiaries to build peaking capacity sometime after the year 2000.

AEP's current resource plan indicates that the need for new coal-fired base load generation will not occur until sometime after the year 2005. The size of any new coal-fired generation will most likely be significantly smaller than the 1,300MW units previously added to the AEP system in order to better match projected modest load growth.

KPCo participates with 26 other electric utilities operating in nine states in the East Central Reliability Coordination Agreement (ECAR), which was established to further the reliability of bulk power supply in the region through coordination of the planning and operation of ECAR members of their bulk power supply facilities. The ECAR members have established principles and procedures regarding matters affecting the reliability of the bulk power supply within the ECAR region.

OPERATIONS

The five major AEP operating subsidiaries participate in various contractual agreements, which define how each subsidiary shares in the cost and benefits associated with the system's generating plants, transmission capacity, and wholesale sales to nonaffiliated electric utilities. This sharing is based on each operating 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

Fuel and power supply

	1994	1993	1992	1991
*Generating capacity**				
Owned (MW)	23,932	23,626	23,934	23,681
Firm purchased (MW)	135	184	268	439
Peak demand (MW-winter)	19,388	18,237	17,649	17,731
Reserve margin (%)	24.9	31.4	38.0	37.0
Peak growth (%)	6.3	3.3	(0.5)	2.6
Annual load factor (%)	54.0	64.0	65.7	66.5
ECAR regional reserve margin (%-summer)	17.1	18.7	29.7	24.6
Generation by fuel source (%)				
Coal	60.2	60.0	66.8	55.5
Purchased	39.8	40.0	33.2	44.5

p—Preliminary data. *Based on AEP System. ECAR—East Central Area Reliability Coordination Agreement. N.A.—Not available. MW—Megawatts. *Source:* Edison Electric Institute.

REGULATION Retail rates are regulated by the KPSC, while wholesale rates are regulated by the FERC. For the next few years, absent a major construction program, the company's rate relief requirements should be manageable. The bulk of base rate needs center on recovery of AEP system power pool charges.

MANAGEMENT AEP is one of the best-managed companies from an operating performance basis. High levels of efficiency and productivity have helped to keep energy prices competitive. The company is well known for its expertise in building and operating large coal-fired units. With low electric rates, power to sell, and the most extensive transmission system in the country, AEP is a formidable competitor. Management has become more aggressive as evidenced by the 1995 five-year 50MW sale to Cleveland Public Power beginning later this year and a 200MW sale over 15 years to the North Carolina Electric Membership Corp., which began in early 1996. Further competitive gains are expected.

In December 1995, AEP began offering a different kind of system sales transaction called coal conversion. Under this concept, AEP contracts with a third party (usually a power marketer) to supply energy based on this new service from AEP power plants, generally in off-peak periods. The power marketer supplies the coal to the company's power plants. AEP converts the coal into electricity for the marketer, which then sells it to the ultimate buyer. This coal conversion was instrumental in increasing AEP's wholesale sales in the first half of 1996.

While operations have been superior, management's regulatory relations have been confrontational, sometimes to the detriment of investors. Yet, under the leadership of Linn Draper, regulatory relations are expected to be less adversarial. Management's commitment to credit quality is overshadowed by efforts to enhance shareholder value, as evidenced by high debt leverage and a relatively high common dividend payout.

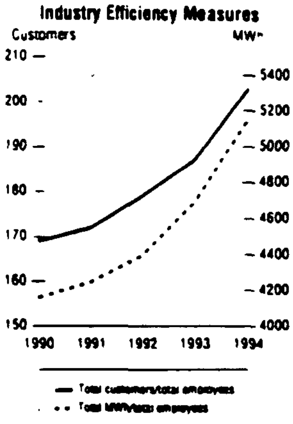
With limited domestic growth in AEP's core regulated domestic electric business, management will be more aggressive in nonregulated endeavors. For example, AEP management believes that future growth opportunities in various emerging markets are more attractive than the mature domestic market. The utility is

Regulation

Regulatory agency	Kentucky Public Service Commission	
State	Kentucky	
Case period	Six months.	
Interim procedures	Rarely.	
Authorized returns (Last 12 to 18 months)		
Return on equity (electric)	11.50	
Return on equity (gas)	11.50	
Return on equity (telephone)	N/A	
Rate base	Average original cost.	
Test period	Forecasted.	
CWIP	CWIP included in rate base for full cash return.	
Adjustment mechanisms	Fuel and purchased power adjustment clauses (automatic), the energy component of purchased power is recovered through the fuel clause. The capacity component is recovered through base rates; gas cost adjustment clause permitted monthly based upon actual costs for the second preceding month, with an under-/overrecovery mechanism included.	
Incentive ratemaking	Rate of return.	
Commissioners	Party	Term
Linda Breathitt, Chair	Democrat	July 1997
Edward J. Holmes	Democrat	July 1999
Robert M. Davis	Democrat	July 1998

Source: Regulatory Research Associates Inc. N/A—Not applicable.

Industry Efficiency Measures



demands of all major operating units during the preceding 12 months. In 1995, KPCo received from the AEP system $23 million for generating capacity, $3.5 million for transmission, and $5.0 million for off-system AEP sales.

The AEP system is one of the strongest transmission systems in the world, with almost 22,000 circuit miles of transmission and 101,000 miles of distribution lines, which connect customers with AEP's 39 power plants. The AEP transmission system, with 119 high-voltage interconnections to 29 other utilities, provides an important link between the East Coast and the Midwest and Canada and the Mid-South.

In addition to the AEP system, KPCo is directly interconnected with unaffiliated Kentucky Utilities Co., East Kentucky Power Cooperative, and the Federal government's Tennessee Valley Authority.

AEP's compliance strategy for the Clean Air Act centers on the 1995 installation of scrubbers at the two-unit 2,600MW Gavin Plant owned by affiliate, OPCo. KPCo's clean air capital cost for Phase 2, ending Jan. 1, 2000, will require an additional $6 million of spending.

One of the important strengths of the AEP system is the performance of its electric generating equipment. In 1994, total energy costs of the five major operating subsidiaries on an unweighted basis averaged 3.92 cents per kilowatt-hour (kWh) compared with the region's average of 4.83 cents per kWh. AEP is strongly committed to achieving superior operational performance. For example, in 1995, AEP's system heat rate, which measures the amount of energy it takes to produce one kilowatt of electricity, was 9,818 Btu per kWh—substantially better than the 1995 estimated industry average of 10,394 Btu per kWh.

ASSET CONCENTRATION The company's largest investment is its 1,060MW coal-fired Big Sandy plant with a net book value of $106.2 million, which represented 48.1% of KPCo's year-end 1995 common equity and 19.2% of capitalization. The Big Sandy plant represents 100% of KPCo's generating capability.

Efficiency statistics
Operating efficiency (electric-retail)

	1995p	1994	1993	1992	1991
Total customers/employee	209	198	189	183	172
Industry avg.	N.A.	204	188	180	172
Total MWh/total employee	7,976	7,236	6,874	6,635	6,331
Industry avg.	N.A.	5,148	4,681	4,368	4,224
Total revenue/total kWh (cents)	4.24	4.19	4.18	4.36	4.41
Industry avg.	N.A.	7.19	7.24	7.14	7.08

p—Preliminary data. N.A.—Not available. kWh—Kilowatt-hours. MWh—Megawatt-hours. *Source:* UDI/McGraw-Hill.

Base load statistics
Year-end 1994

Plant	Units	% of ownership	Fuel	Alt. fuel	Gross capacity (MW)	Net generation (GWh)	Heat rate (Btu)	Capacity factor (%)	Installed cost/kW ($)	Fuel exp./kWh (cents)	Total var. prod. exp./kWh (cents)
Big Sandy	1-2	100.0	Coal	None	1,097	5,842	9,409	60.8	204	1.08	1.45

MW—Megawatts. GWh—Gigawatt-hours. kW—Kilowatt. kWh—Kilowatt-hours. Btu—British thermal units. *Source:* UDI/McGraw-Hill.

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exploring investing in China. AEP may add debt at the parent level to support its potential China investment.

In addition, management may be biding its time while waiting for the region's frail electrics to crater. Regardless, a strong operational base gives AEP management a lot of flexibility and options in this rapidly changing business environment.

EARNINGS ANALYSIS

For the first six months of 1996, KPCo's earnings declined 12.5% to $9.1 million, compared with the year earlier earnings of $10.4 million. Lower earnings largely reflected an increase in operating and maintenance expense, a write-down of certain demand-side management equipment to market value, and higher interest expense, which more than offset increased sales resulting from favorable weather and an expanding economy.

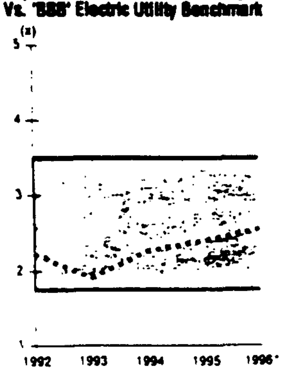
In 1995, KPCo's earnings decreased by $0.1 million because of severance pay and increased interest expense. Going forward, earnings will be heavily dependent on retail sales growth, and management's ability to control costs. Forecasted retail sales growth of about 1.4% annually should permit modest earnings improvement. However, heavy external funding requirements will result in higher interest expense levels, which will place downward pressure on earnings protection measures. Adjusted pretax interest coverage is projected to be in the 2.25 times (x) to 2.50x range during the next five years, compared with the current level of 2.56x as of March 31, 1996. The company's 1995 issue of $40 million junior subordinated deferrable interest debentures was given preferred equity treatment, which will help maintain adjusted interest coverages and debt leverage.

CASH FLOW ANALYSIS

Cash construction expenditures for 1996 to 2000 are budgeted at about $309 million, which is a relatively high level given no new major plant construction. Depreciation and amortization over the same period is forecasted at about $140 million. Over the next five years, capital spending will average a relatively high 9.5% of total capitalization.

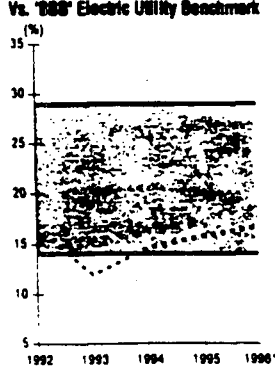
Prospectively, net cash flow will cover only a relatively small 40% of planned capital spending through 2000. Funds from operations interest coverage will be under downward pressure as a consequence of heavy external funding needs and higher projected debt levels with resulting greater interest expense. Thus, pro-

Adjusted Pretax Interest Coverage Vs. 'BBB' Electric Utility Benchmark



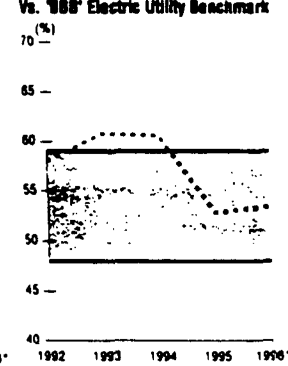
*For 12 months ended March 31 (unaudited)

Adjusted FFO/Avg. Total Debt Vs. 'BBB' Electric Utility Benchmark



*For 12 months ended March 31 (unaudited).

Adjusted Total Debt/Total Capital Vs. 'BBB' Electric Utility Benchmark



*For 12 months ended March 31 (unaudited) jected adjusted funds from operations interest coverage is expected to range from 3.0x to 3.5x, compared with the current level of 3.64x as of March 31, 1996. In addition, funds from operations to average adjusted debt should range from 13% to 15% during the next five years, compared with the current level of 16.7%.

BALANCE SHEET ANALYSIS

At March 31, 1996, adjusted debt leverage was 53.5%. In April 1995, KPCo issued $40 million of 8.72% junior subordinated deferrable interest debentures due 2025. The proceeds from this offering were used to pay down short-term debt. This issue was given preferred equity treatment for analytical purposes by Standard & Poor's. Such treatment and planned equity infusions by AEP should result in an adequate capital structure.

Credit ratings are predicated on maintenance of a balanced capital structure, which will require meaningful equity infusions from parent, AEP, during the next five years. Standard & Poor's believes that KPCo will not be able to reduce materially adjusted debt leverage over the next five years given external funding needs. However, preferred equity treatment for the April 1995 junior subordi-

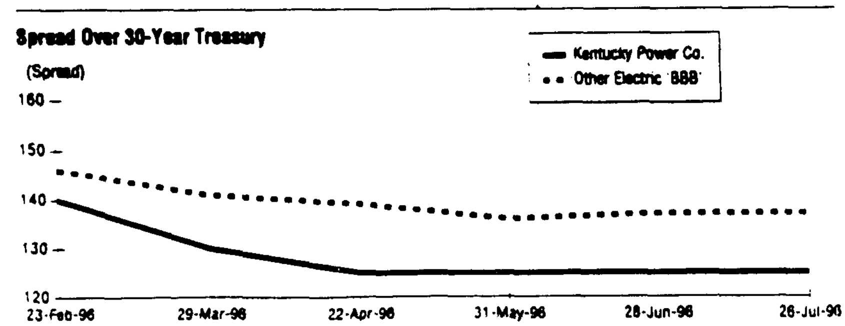
Financing flexibility

Common equity characteristics as of Dec. 31, 1995	
Ticker symbol	AEP
Stock price ($)	40 4/8
PE ratio (x)	14.2
Dividend yield (%)	5.9
Market to book (%)	174.2
Dividend to book (%)	10.3
Debt characteristics at fiscal year ended 1995	
Secured debt (%)	86
Unsecured debt (%)	0
Subordinated debt (%)	14
Fixed-rate debt (%)	100
Variable-rate debt (%)	0
Avg. life of long-term debt (years)	12
Embedded cost of long-term debt (%)	7.8
Debt maturing in five years (mil. $)	35.0

Short-term financing
As of Dec. 31, 1995

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	0.0	11.0			
Bank lines					
Contracted committed lines	100.0	16.0	12/96	Yes	N.A.
Avg. cost of short-term debt (%)	6.0				

MAC—Material adverse change. N.A.—Not available.



nated deferrable interest debenture issue has resulted in lower leverage levels for analytical purposes.

Regulatory assets at year-end 1995 were a modest $4.8 million, excluding $77.6 million due from customers for future federal income taxes. Regulatory assets are expected to be recovered in future periods through the ratemaking process.

FINANCING FLEXIBILITY

KPCo received from its parent, AEP, a cash capital contribution of $10 million in March 1996, which was credited to paid-in capital. In April 1996, KPCo refinanced $45 million of 7 7/8% first mortgage bonds due in 2002 with the proceeds of two $25 million term loan agreements due in 1999 and 2000 at 6.42% and 6.57% annual interest rates, respectively. The redemption of this series of first mortgage bonds removed the restriction on the use of retained earnings for common stock dividends.

KPCo has adequate financing flexibility given its membership in the AEP family. At Dec. 31, 1995, unused short-term lines of credit shared with AEP system companies of $372 million were available; however, provisions of PUHCA limit short-term borrowing to $150 million. At year end 1995, KPCo's outstanding short-term borrowings totaled about $27.1 million. In addition, the utility has guaranteed $10.3 million of loans related to customer purchase of efficient electrical equipment. Periodic reductions of outstanding short-term debt are made through issuance of long-term debt, and equity capital contributions by AEP. In 1995, AEP made a cash capital contribution of $10 million.

In April 1995, KPCo issued $40 million of 8.72% junior subordinated deferrable interest debentures due 2025 and used the proceeds to reduce short-term debt.

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Financial statistics

Kentucky Power Co.	1996*	1995	1994	1993	1992
	—Year ended Dec. 31—				
Income statement (mil. $)					
Gross revenues	331.4	328.1	307 4	294 3	313.2
Operating expenses (excl. DD&A)	253.4	250.4	235.7	231.8	241.8
Depreciation and amortization	24.7	24 4	23.0	22.3	21 6
Pretax operating income	53.3	53.3	48.7	40.2	49 8
Gross interest expense	20.2	21.6	21.2	21 0	22.3
Pretax income	32.0	30.8	27.5	19.7	28.0
AFUDC and deferrals	0.4	0.4	0.5	0.3	0 4
Income taxes	4.8	4.3	2.2	1.6	1.5
Net income from continuing operations	27.2	26.5	25.3	18.0	26 5
Earnings protection					
Pretax interest coverage (x)	2.57	2.41	2.27	1.92	2.23
Adjusted pretax interest coverage (x)	2.56	2.40	2.26	1.91	2.23
Preferred dividend coverage (x)	2.04	2.04	2.27	1.92	2.23
EBITDA interest coverage (x)	3.79	3.54	3.36	2.98	3.20
AFUDC and deferred income/earnings (%)	1.4	1.4	1.9	1.5	1.5
Return on common equity (nominal) (%)	10.5	11.1	12.5	9.2	13.3
Common dividend payout (%)	98.1	95.9	84.7	125.8	80.5
Annual O&M growth (%)	3.6	2.7	5.7	16.6	N.A.
Annual expense growth (excl. DD&A) (%)	1.2	6.2	1.7	(4.1)	N.A.
O&M/revenues (%)	22.9	22.3	23.2	22.9	18.4
Total operating expenses (excl. DD&A)/revenues (%)	76.5	76.3	76.7	78 8	77.2
Balance sheet (mil. $)					
Cash and equivalents	1.0	1.0	0.9	0.9	1.1
Gross plant	885.9	879.7	851.9	807.4	780.9
Net plant	612.7	609.1	591.9	558.8	542.5
Total assets	773.1	772.2	739.8	670.4	616.7
Short-term debt	48.3	58.6	57.0	39.7	71.9
Long-term debt	263.1	232.5	261.7	260.1	203.5
Preferred stock	40.0	40.0	0.0	0.0	0.0
Common equity	231.3	220.6	208.4	194.5	199.2
Total capitalization	582.6	551.9	527.0	494.3	474.6
Total off-balance-sheet obligations	1.2	1.2	2.1	2.1	0.0
Balance sheet ratios (%)					
Short-term debt/total capital	8.3	10.7	10.8	8.0	15.2
Long-term debt/total capital	45.2	42.1	49.6	52.6	42.9
Preferred stock/total capital	6.9	7.2	0.0	0.0	0.0
Common equity/total capital	39.7	40.0	39.5	39.3	42.0
Adjusted total debt/total capital	53.5	52.9	60.6	60.8	58.0
Debt/EBITDA (x)	4.1	3.8	4.5	4.8	3.9
Cash flow (mil. $)					
Net income	27.2	26.5	25.3	18.0	26.5
Depreciation	24.7	24.5	23.1	22.4	21.7
Deferred taxes and ITC	(3.0)	(3.9)	(2.7)	(1.8)	(4.5)
AFUDC and deferrals	(0.4)	(0.4)	(0.5)	(0.3)	(0.4)
Other FFO adjustments	1.5	1.2	(0.2)	(4.4)	3.3
Funds from operations (FFO)	50.1	48.0	45.0	34.0	46.6
Preferred dividends	(3.5)	(2.6)	0.0	0.0	0.0
Common dividends	(23.3)	(22.9)	(21.4)	(22.7)	(21.4)
Net cash flow (NCF)	23.3	22.4	23.6	11.3	25.3
Working capital changes	(1.5)	(3.9)	0.9	2.7	6.7
Capital expenditures (capex)	(39.9)	(38.9)	(52.6)	(35.0)	(31.3)
Discretionary cash flow	(16.1)	(20.4)	(28.2)	(21.0)	0.7
Cash flow adequacy					
Capex/avg. total capital (%)	7.0	7.2	10.3	7.2	6.6
NCF/capex (%)	58.5	57.6	44.8	32.2	80.0
FFO/avg. total debt (%)	16.6	15.7	14.5	11.8	16.9
Adjusted FFO/avg. total debt (%)	16.7	15.8	14.6	11.9	16.9
FFO interest coverage (x)	3.64	3.30	3.09	2.52	3.03
Adjusted FFO interest coverage (x)	3.64	3.31	3.09	2.53	3.03

*For 12 months ended March 31 (unaudited). N.A.—Not available. AFUDC— Allowance for funds used during construction. O&M—Operations and maintenance. ITC—Investment tax credits. DD&A—Depreciation, depletion, and amortization. EBITDA—Earnings before interest, taxes, depreciation, and amortization.

Notes

Notes

UTILITY CREDIT REPORT

STANDARD & POOR'S
Utilities Rating Service

KENTUCKY POWER CO. (AMERICAN ELECTRIC POWER CO. INC. UNIT)

ISSUER CREDIT RATING	BBB+
OUTLOOK	STABLE

Analyst: Steve Zimmerman (212) 208-1658; Company contact: John S. Bilacic (614) 223-2847

OUTSTANDING RATINGS

Senior secured debt	BBB+
Junior subordinated debentures	BBB

OUTLOOK: STABLE
ELECTRIC BUSINESS POSITION: Somewhat above average (2)

DEBT RATING HISTORY

SENIOR DEBT	BBB+	1995
	BBB+	1994
	BBB+	1993
	BBB+	1992
	BBB+	1991
	BBB+	1990

RATIONALE

Kentucky Power Co.'s creditworthiness is enhanced by its membership in the American Electric Power Co. Inc. (AEP) system. The company's ratings largely eflect AEP's somewhat above average business position evaluation and consolidated financial profile. System internal funds generation and cash interest coverage are expected to remain adequate, although debt leverage continues to be aggressive. AEP's challenges include increasing wholesale profitability, a cyclical industrial load, strict state rate regulation, and acid rain exposure.

In late 1988, the Kentucky Power Service Commission (PSC) approved a settlement agreement providing for full recovery of costs associated with Rockport unit power purchases and transmission equalization payments. Previously, the Kentucky commission had limited recovery to the less expensive AEP power pool embedded cost rate rather than the more costly Rockport unit power agreement. Still, Kentucky Power's interest coverage and capitalization ratios after adjusting for capacity payments associated with long-term contracted Rockport power purchases are weak, but supported by the system's stronger financial condition. For the foreseeable future, projected Kentucky Power spending will require significant external funding, which will pressure financials. Common equity infusions from parent AEP will be needed to maintain a balanced apital structure.

OUTLOOK

Strong consolidated AEP operations provide ratings stability and support for maintenance of Kentucky Power's credit quality. Significant capital spending relative to Kentucky Power's size and cash flow generation capability will restrain credit improvement for this AEP subsidiary. Acid rain spending, purchased power, and lackluster projected retail sales growth add risk but are largely reflected in ratings.

Financial summary (Mil. $)	1995*	1994	1993	1992	1991
Gross revenues	302.3	307.4	294.3	313.2	306.8
Net income from continuing operations	23.0	25.3	18.0	26.5	28.5
Funds from operations (FFO)	37.4	45.0	34.0	46.6	43.2
Net cash flow	15.3	23.6	11.3	25.3	22.8
Capital expenditures	47.8	52.6	35.0	31.3	28.8
Total capital	526.6	527.0	494.3	474.6	471.6
Adjusted ratios					
Pretax interest coverage (x)	2.03	2.26	1.91	2.23	N.A.
Total debt/total capital (%)	60.8	60.6	60.8	58.0	N.A.
FFO interest coverage (x)	2.62	3.09	2.53	3.03	N.A.
FFO/avg. total debt (%)	11.8	14.6	11.9	16.9	N.A.

*For 12 months ended June 30 (unaudited). N.A.—Not available.

Operating summary	1994	1993	1992	1991	1990
Growth (%)					
Retail (MWh)	3.0	1.7	(0.2)	3.4	2.2
Retail-customers	1.5	1.5	1.2	1.0	1.0
Capacity-MW	22,149	22,974	23,508	23,397	20,792
Reserve margin (%)	15.1	27.0	34.3	33.3	24.2
Rates (cents/kWh)					
Residential	4.97	4.94	5.12	5.13	5.28
Commercial	5.21	5.21	5.41	5.44	5.62
Industrial	3.24	3.25	3.47	3.54	3.55

MW—Megawatts. MWh—Megawatt-hours. kWh—Kilowatt-hours.

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KENTUCKY POWER CO.

RECENT DEVELOPMENTS

July 1995. AEP announced a severance plan to eliminate about 1,200 jobs at 16 fossil fuel power plants in five states. This is another significant step in AEP's comprehensive restructuring plan to improve performance and ensure competitiveness. The plan is one part of an overall restructuring program across AEP's seven-state service area to realign functionally into separate power generation and energy delivery groups.

Staff reductions are expected to begin sometime in early October and continue into 1996. Downsizing will affect power generation plants in West Virginia, Virginia, Ohio, Kentucky, and Indiana. AEP's fossil fuel plants currently employ about 5,200 workers.

In the future, AEP fossil-fuel plants will be staffed to perform running maintenance—that is, maintenance performed while the generating units are producing energy—rather than being staffed for both running maintenance and scheduled outages.

July 1995. AEP reported second-quarter 1995 earnings of $96.5 million, a 7% decrease from the $103.8 million earned in 1994. Earnings per share for the quarter were 52 cents, a decrease from 56 cents reported for the same period in 1994.

For the 12 months ended June 30, 1995, earnings increased 24.6% to $487.6 million from $391.2 million. Per share earnings rose from $2.12 to $2.63. The increase in earnings and earnings per share was predominantly due to a $144.5 million after-tax write-off recognized in third-quarter 1993, stemming from a disallowance by the Public Utilities Commission of Ohio of a portion of the company's investment in the Zimmer generating station.

Exclusive of the disallowance, earnings and earnings per share for the 12 months ended June 30, 1994 would have been $535.8 million and $2.90, respectively. On this basis, there would have been a 9.0% decrease in 1995 12-month earnings compared with 1994 12-month earnings.

Operating revenues for the second quarter were $1.31 billion, a 3.2% decrease from revenues of $1.45 billion in 1994. For the June 30, 1995 12-month period, revenues of $5.39 billion were down 3.3% from revenues of $5.57 billion in 1994. AEP attributed the decrease in revenues, earnings, and earnings per share for the 12-month period, exclusive of the Zimmer disallowance, to reduced sales because of milder weather in the current period. Earnings also were affected by an increase in operating expenses. The year-to-year decline in second-quarter revenues and earnings resulted from a return to normal temperatures compared with unseasonably warm weather in 1994.

June 1995. AEP realigned its organization structure to create a distinct power generation group and an energy transmission and distribution group. At this time, there are no changes in asset ownership or formal legal entities. In addition, AEP plans to offer an extensive array of services outside of its traditional service territory and regulated business lines. Performance improvements also are planned, such as increasing the availability of AEP generating units, reducing fuel costs, increasing efficiencies in purchasing and materials management, implementing an activity based management system (ABMS), and investing in new technology and employee development. Furthermore, AEP plans to gradually phase out operating company identification. Management intends to enhance brand loyalty to the AEP name as a result of increasing competition and deregulation.

April 1995. Columbus Southern Power Co. submitted a proposal to acquire the city of Columbus' trash-burning power plant and the electric system of the city of

Columbus. The trash-burning facility would be idled until possible repowering with gas-fired combustion turbines. The city's electric system has about 11,000 customers and annual revenues of about $32 million.

April 1995. AEP reached tentative agreement with most of the parties involved in hearings before the U.S. Federal Energy Regulatory Commission (FERC) on the company's proposed wholesale transmission open-access tariff.

April 1995. AEP won a 15-year contract to supply 200 megawatts (MW) of electric power to the North Carolina Electric Membership Corp., beginning in 1996. The company also has completed contracts with PECO Energy Co. for 275MW during 1995 and a five-year agreement to supply up to 50MW of power to Cleveland Public Power beginning in 1996.

AEP also has signed an agreement with Steel Dynamics Inc. to locate a $500 million steel minimill in Indiana, making it the largest customer of Indiana Michigan Power Co., an AEP operating company.

MAJOR STRENGTHS AND RISKS

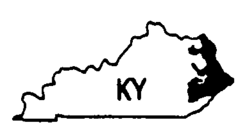
Major strengths:

- AEP family membership.
- Low-cost producer with low rates.
- No nuclear exposure.

Major risks:

- Below-average sales growth prospects compared with AEP consolidated.
- Less favorable system settlements, given Ohio Power's recent investment in scrubbers for the Gavin plant.
- Kentucky rate regulation has been favorable for most electrics, but not for AEP.
- Industrialized service territory with above-average unemployment.

KENTUCKY POWER CO.



Neighboring utilities

1. Appalachian Power Co.
2. Kentucky Utilities Co.
3. Old Dominion Power Co.
4. Ohio Power Co.

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CORPORATE STRUCTURE

Kentucky Power is the smallest of the five major operating subsidiaries of the AEP system. AEP is a registered public utility holding company that owns directly or indirectly all of the common stock of its operating electric utility subsidiaries. The service area of AEP's electric subsidiaries contains seven million people and covers portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The total AEP service territory covers 45,400 square miles. The generating and transmission facilities of AEP's subsidiaries are interconnected, and their operations are coordinated as a single integrated electric utility system. Substantially all of the operating revenues of the AEP system are derived from providing electric service.

AEP continues to study nonregulated business opportunities, particularly those that relate to the company's electric expertise. Such endeavors are conducted through AEP Energy Services Inc. and AEP Resources Inc.

AEP Electric Services offers various consulting services domestically and internationally that relate to the company's electric expertise. AEP Resources' primary business is development and investment in exempt wholesale generators, foreign utility companies, qualifying cogeneration facilities, and other power projects. Currently, AEP Resources has no interest in any power projects. However, the company is in preliminary development of a number of projects, including the development of two 1,300MW generating stations in China. AEP and AEP Resources have received approval from the SEC under the Public Utilities Holding Company Act of 1935 (PUHCA) to finance up to $300 million for investment in exempt wholesale generators and foreign utility companies.

On a consolidated basis, AEP's overall creditworthiness is viewed as a weak 'A-', strong 'BBB+', given a somewhat above average business position evaluation.

Service area economics* (% chg.)

	1992	1993	1994	1995-1997§	1995-2005§
Manufacturing employment					
Service territory	2.7	0.3	1.2	(1.9)	(1.7)
ECAR region	(0.0)	0.4	1.7	(1.5)	(1.6)
National	(1.6)	(0.0)	(0.1)	(1.4)	(1.5)
Nonmanufacturing employment					
Service territory	0.9	5.7	6.7	2.0	1.7
ECAR region	1.5	1.6	2.0	2.1	1.6
National	0.7	2.2	3.0	2.4	1.9
Total employment					
Service territory	1.1	4.9	6.0	1.6	1.4
ECAR region	1.1	1.3	1.9	1.4	1.0
National	0.3	1.8	2.5	1.8	1.4
Population					
Service territory	0.0	1.8	2.6	1.2	1.1
ECAR region	0.7	0.7	0.6	0.5	0.5
National	1.1	1.0	1.0	0.9	0.9
Private housing starts					
Service territory¶	33.9	9.4	(5.5)	1.4	0.8
ECAR region	24.5	2.5	(0.7)	0.5	(0.0)
National	18.8	7.5	7.0	1.7	1.2
Unemployment rate					
Service territory¶	6.9	6.4	4.9	5.1	5.6
ECAR region	7.7	6.7	5.8	5.7	6.3
National	7.6	7.4	6.1	5.9	5.9
Real per capita income (1987 $)					
Service territory¶	13,369	13,546	13,923	14,784	16,316
ECAR region	15,188	15,415	15,930	16,726	18,269
National	16,319	16,428	16,822	17,764	19,700

*Economic variables determined by the aggregation of metropolitan areas provided by the company. §Employment, population, and housing start estimates represent compound annual growth rates for the period. Unemployment and real per capita income estimates represent forecasts for the last year in the period. ¶Data represent the largest metropolitan area(s) in the service territory. ECAR—East Central Area Reliability Coordination Agreement.

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Thus, the senior secured debt of the operating subsidiaries will tend to be in the 'BBB+' to 'A-' range.

SERVICE AREA

Industries served
1994

Industry type	Sales (%)	Revenue (%)
Coal mining	38.9	47 5
Petroleum refining	31.0	24 6
Primary metal	17 0	15.2
Chemicals	9 6	7.9
Total (GWh/mil. $)	2,870	93

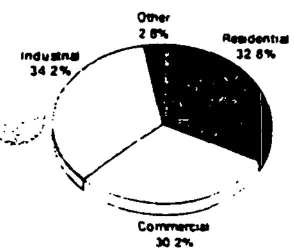
GWh—Gigawatt-hours. *Source:* Edison Electric Institute.

Kentucky Power accounts for about 6% of AEP's internal electric sales. This AEP subsidiary serves about 163,000 retail customers in eastern Kentucky. The service territory's industrial base includes coal mining, primary metals, industrial chemicals, and petroleum refining. These industries are mature, slow growing businesses, which are expected to result in sluggish electric sales growth over the long term.

At March 31, 1995, the unemployment rate in Kentucky Power's service territory was a very high 8.0% compared with only 5.0% for the entire state of Kentucky and 5.7% for the nation. The closing of a significant portion of a local steel mill, combined with stagnant employment in area core industries, largely account for high unemployment levels.

SALES

Industry Retail Sales (Mwh)
1994



Source Edison Electric Institute

Kentucky Power's long-term average annual growth rate for sales to retail customers is projected at 1.4% compared with the consolidated AEP sales growth rate of 1.8%. Kentucky Power's long-term growth rate for residential sales is forecasted at 1.2%, commercial 2.3%, and industrial 1.2%.

For the first six months of 1995, retail energy sales increased about 2.1% compared with the year-ago period. Sales to industrial customers expanded 6.5%, reflecting strength in local industrial output, while mild weather reduced residential sales about 2.8%. Wholesale energy sales decreased 9.6% as a result of lower energy sales to unaffiliated utilities by the AEP system power pool.

For the year ended Dec. 31, 1994, Kentucky Power's retail electric sales increased 3.0% compared with the year-earlier period, while wholesale sales increased about 11.1%. Retail sales were helped in 1994 by favorable weather and stronger industrial demand. For example, Kentucky Power's 1994 residential sales increased

Market segments

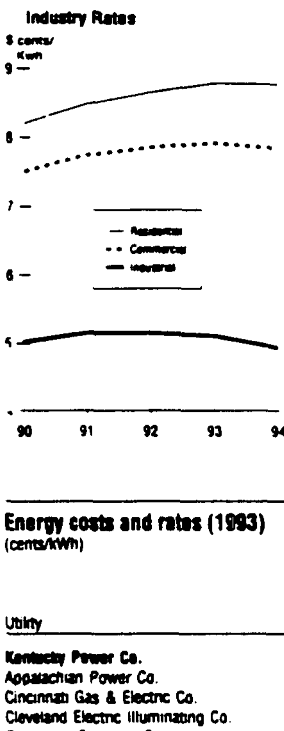
	1994	1993	1992	1991	1990
Sales					
Total retail (GWh)	5,977	5,802	5,706	5,717	5,529
Residential (%)	33.9	34.0	33.1	33.2	31.1
Commercial (%)	17.9	17.8	17 4	17.3	16.6
Industrial (%)	48.0	48.0	49.4	49.4	52.1
Other (%)	0.2	0.2	0.2	0.2	0.2
Wholesale (GWh)	3,304	3,114	4,105	2,930	4,679
Total sales (GWh)	9,281	8,916	9,811	8,647	10,208
Revenue					
Total retail (mil. $)	250	243	249	252	245
Residential (%)	40.2	40.2	38.8	38.7	37 0
Commercial (%)	22.3	22.2	21.6	21.4	21.1
Industrial (%)	37.1	37.3	39.3	39.6	41 7
Other (%)	0.3	0.3	0.3	0.3	0.3
Wholesale (mil. $)	54	48	61	52	85
Total revenue (mil. $)	304	291	310	304	331
Annual sales growth (%)					
Residential	2.7	4.5	(0.6)	10.4	(1.0)
Commercial	3.7	4.3	0.2	7.5	3.8
Industrial	3.0	(1.2)	(0.0)	(2.1)	3.7
Total retail	3.0	1.7	(0.2)	3.4	2.2
Standard & Poor's retail avg.	2.6	3.6	0.3	2.0	1 9
Wholesale	6.1	(24.1)	40.1	(37 4)	219.9
Total sales growth	4 1	(9.1)	13 5	(15.3)	48.5
Retail customer growth	1 5	1 5	1 2	1 0	1 0

GWh—Gigawatt-hours. *Source:* UDI/McGraw Hill.

about 2.7%, while commercial volume gained 3.7% and industrial sales expanded 3.0% compared with 1993 sales. Wholesale energy sales advanced 6.1%, reflecting increased availability of generating equipment and a new wholesale supply agreement. Kentucky Power's internal load factor is estimated to continue in the 57%-59% range.

COMPETITIVE POSITION

AEP, via its five main operating subsidiaries, controls the largest electric utility system in the Midwest. AEP is among the lowest-cost producers in the region—and, unlike the region's other low-cost producers, AEP actually has power to sell. If AEP wanted to add some peaking units and operate with a thinner reserve margin, it might have as much as 4,000MW to sell, plus another 800MW if Ohio's aluminum industry closes.



With low electric rates, low production costs, available capacity for sale, and the most extensive transmission system in the country, the AEP system is a formidable competitor. The operating subsidiaries of AEP are expected to benefit if retail wheeling is adopted. In a fully competitive environment, AEP will probably focus on the high-cost northern Ohio utilities, Centerior Energy Corp. and Ohio Edison Co., as well as eastern markets that offer excellent opportunity in a competitive market. AEP also may have more cost-cutting opportunities going forward than other regional electrics due to AEP's size and its corporate realignment, which creates a distinct generation group and an energy transmission and distribution group. Acquisition of weaker regional electrics at favorable prices also may be possible.

Energy costs and rates (1993)
(cents/kWh)

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Kentucky Power Co.	**1.22**	**1.63**	**0.33**	**2.48**	**2.18**	**3.08**	**4.84**	**5.21**	**3.25**
Appalachian Power Co.	1.95	2.40	0.90	2.06	2.76	3.86	5.73	5.25	3.84
Cincinnati Gas & Electric Co.	1.59	2.03	1.87	1.67	3.77	4.75	7.13	6.51	4.54
Cleveland Electric Illuminating Co.	1.51	2.79	3.85	9.50	6.82	8.35	10.93	9.52	6.45
Columbus Southern Power	1.61	2.24	1.87	3.03	3.78	5.10	7.29	6.07	4.68
Consumers Power Co.	1.65	2.80	1.87	4.22	4.47	6.08	7.08	6.88	5.43
Dayton Power & Light Co	1.54	2.00	2.19	1.86	4.02	5.21	8.20	6.66	5.04
Detroit Edison Co.	1.67	2.41	2.12	3.07	4.46	5.81	9.35	8.93	5.63
Duquesne Light Co.	1.59	2.43	2.15	2.22	4.48	6.32	12.40	8.56	6.13
Indiana Michigan Power Co.	0.81	1.68	1.14	2.22	2.71	3.21	6.20	5.56	4.16
Indianapolis Power & Light	1.20	1.69	0.99	5.98	2.77	3.68	5.61	5.79	4.15
Kentucky Utilities Co.	1.29	1.64	0.63	1.80	2.21	3.09	4.48	4.30	3.38
Louisville Gas & Electric Co.	1.25	1.81	1.14	1.52	2.82	3.48	6.04	5.60	3.82
Monongahela Power Co.	1.53	2.03	0.79	3.53	3.04	4.08	6.88	6.07	4.03
No. Indiana Public Service	1.75	2.49	1.77	1.43	4.03	5.27	10.07	8.60	4.67
Ohio Edison Co.	1.48	2.42	2.77	1.82	4.97	6.20	10.67	9.50	6.24
Ohio Power Co.	1.66	2.05	0.69	1.67	2.64	3.35	6.34	5.47	3.16
Potomac Edison Co.	1.56	2.06	0.81	3.04	2.94	3.93	6.62	5.96	3.39
PSI Energy Inc.	1.52	1.85	0.74	1.95	2.56	3.48	5.79	4.58	3.43
Southern Indiana Gas Electric	1.67	2.22	1.18	1.57	3.21	3.87	6.48	5.53	3.86
Toledo Edison Co.	1.53	3.09	4.94	6.24	7.95	9.29	11.23	10.76	6.46
West Penn Power Co.	1.55	2.02	0.90	3.35	3.05	4.06	6.32	5.53	4.35
ECAR region	1.52	2.19	1.64	2.93	3.67	4.77	7.51	7.07	4.54
Standard & Poor's average	1.60	2.46	1.94	4.16	4.31	5.78	8.78	7.92	5.11

kWh—Kilowatt-hours. ECAR—East Central Area Reliability Coordination Agreement. *Source:* UDI/McGraw Hill

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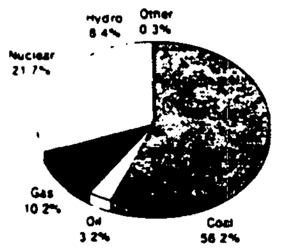
FUEL AND POWER SUPPLY

Industry Fuel Mix
1994



Source: Edison Electric Institute

AEP derives about 85% of its electric generation from coal-fired units and about 12% from nuclear, with variations largely related to nuclear refueling outages. A small amount of generation comes from hydroelectric generation and other sources. About 65% of AEP's coal requirements are obtained through long-term contracts, 20% from spot or short-term purchases, and 15% from coal reserves that are owned or mined by subsidiaries of AEP. The average cost of coal consumed during 1994 for AEP was $33.95 per ton, and Kentucky Power paid $26.83 per ton. The total average price per million British thermal units (mmbtu) of coal burned in 1994 was $1.52 per mmbtu for AEP and $1.13 per mmbtu for Kentucky Power.

The AEP system's all-time internal electric peak load was 19,236MW, which occurred on Jan. 19, 1994. The net capacity to serve the AEP system load including contractual arrangements was 23,995MW at the time of the January 1994 internal peak demand for a reserve margin of 24.7%. Generating capability, including purchases of 1,450MW for Kentucky Power, compared with a 1995 winter peak demand of 1,372MW (Kentucky Power is a winter peaking company). The resulting 5.7% reserve margin is not a major concern due to access to AEP system generation.

Currently, there are no plans for capacity additions on the AEP system until after the year 2000. Such equipment is likely to be short-lead, simple cycle, gas-fired combustion turbines. Kentucky Power's reserve generating margins are projected at adequate levels for the foreseeable future based on the Rockport unit power purchase contract. Appalachian Power Co., along with Columbus Southern Power Co., are likely to be the next AEP subsidiaries to build peaking capacity sometime after the year 2000.

AEP's current resource plan indicates that the need for new coal-fired base load generation will not occur until sometime after the year 2005. The size of any new coal-fired generation will most likely be significantly smaller than the 1,300MW units recently added to the AEP system to better match projected modest load growth.

Kentucky Power participates with 26 other electric utilities operating in nine states in the East Central Reliability Coordination Agreement (ECAR), which was established for the purpose of furthering the reliability of bulk power supply in the region through coordination of the planning and operation of ECAR members of their bulk power supply facilities. The ECAR members have established principles and procedures regarding matters affecting the reliability of the bulk power supply in the ECAR region.

Fuel and power supply

	1994	1993	1992	1991	1990
Generating capacity					
Owned (MW)	22,149	22,730	23,238	22,958	20,792
Firm purchased (MW)	0	244	268	439	0
Peak demand (MW-winter)	19,236	18,085*	17,499	17,556*	16,744
Reserve margin (%)	15.1	27.0	34.3	33.3	24.2
Peak growth (%)	6.4	3.3	(0.3)	4.8	(5.4)
Annual load factor (%)	54	64	66	67	57
ECAR regional reserve margin (%-summer)	17.1	18.7	29.7	24.6	25.5
Generation by fuel source (%)					
Coal	60	60	67	56	69
Purchased	40	40	33	44	31

*Summer peak. MW—Megawatts. ECAR—East Central Area Reliability Coordination Agreement. *Source:* Edison Electric Institute.

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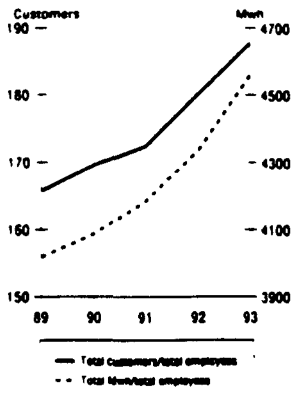
OPERATIONS The five major AEP operating subsidiaries participate in various contractual agreements that define how each subsidiary shares in the cost and benefits associated with the system's generating plants, transmission capacity, and wholesale sales to nonaffiliated electric utilities. This sharing is based on each operating 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 major operating units during the preceding 12 months. In 1994, Kentucky Power received from the AEP system $12 million for generating capacity, $4.3 million for transmission, and $0.8 million for off system AEP sales.

Industry Efficiency Measures



The AEP system is one of the strongest transmission systems in the world, with almost 22,000 circuit miles of transmission and 101,000 miles of distribution lines that connect customers with AEP's 39 power plants. The AEP transmission system, with 119 high voltage interconnections to 29 other utilities, provides an important link between the East Coast and the Midwest, and Canada and the Mid-South.

In addition to the AEP system, Kentucky Power is directly interconnected with unaffiliated Kentucky Utilities Co., East Kentucky Power Cooperative, and the federal government's Tennessee Valley Authority.

AEP's compliance strategy for the Clean Air Act centers on the recent installation of scrubbers at the two-unit 2,600MW Gavin plant owned by affiliate, Ohio Power Co. As a system member, acid rain spending by other AEP affiliates will decrease Kentucky Power's capacity equalization payments from the AEP system. These decreased payments will have to be recovered from the company's ratepayers or absorbed. Kentucky Power's clean air capital cost for Phase 2 ending Jan. 1, 2000 will require an additional $6 million of spending.

One of the important strengths of the AEP system is the performance of its electric generating equipment. In 1993, total variable production costs of the five major operating subsidiaries on an unweighted basis averaged 3.87 cents per kilowatt hour (kWh) compared with the region's average of 4.69 cents per kWh. AEP is strongly committed to achieving superior operational performance. For example, in 1994, AEP's system heat rate—which measures the amount of energy it takes to produce one kilowatt of electricity-was 9,817btu per kWh, substantially better than the 1993 industry average of 10,568btu per kWh.

Efficiency statistics
Operating efficiency (electric-retail)

	1994	1993	1992	1991	1990
Total customers/employee	196	189	183	172	173
Industry avg.	204	188	180	172	169
Total MWh/total employee	7,236	6,874	6,635	6,331	6,227
Industry avg.	5,148	4,681	4,368	4,224	4,136
Total revenue/total kWh (cents)	4.19	4.18	4.36	4.41	4.44
Industry avg.	7.19	7.24	7 14	7.08	6.85

MWh—Megawatt-hours. kWh—Kilowatt-hours. *Source:* UDI/McGraw Hill.

Baseload statistics
Year-end 1993

Plant	Units	% of ownership	Fuel	Alt. fuel	Gross capacity (MW)	Net generation (GWh)	Heat rate (Btu)	Capacity factor (%)	Installed cost/kWh ($)	Fuel exp./kWh (cents)	Total prod. exp./kWh (cents)
Big Sandy	1-2	100.0	Coal	None	1,097 0	5,745	9,363	59.8	192	1 07	1 43

MW—Megawatts. GWh—Gigawatt-hours. Btu—British thermal units. kWh—Kilowatt-hours. *Source:* UDI/McGraw Hill.

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Asset concentration risk. The company's largest investment is its 1,060MW coal-fired Big Sandy plant, with a net book value of $102.3 million. The plant represents 49.1% of Kentucky Power's year-end 1994 common equity and 19.3% of capitalization. The Big Sandy plant represents 100% of Kentucky Power's generating capability.

REGULATION Retail rates are regulated by the Kentucky PSC and wholesale rates are regulated by the FERC. For the foreseeable future, absent a major construction program, Kentucky Power's rate relief requirements should be manageable. The bulk of base rate needs centers on recovery of AEP system power pool charges.

MANAGEMENT AEP is one of the best-managed companies from an operating performance basis. High levels of efficiency and productivity have helped to keep energy prices competitive. The company is well known for its expertise in building and operating large coal-fired units. With low electric rates, power to sell, and the most extensive transmission system in the country, AEP is a formidable competitor. Management has become more aggressive as evidenced by the recent five-year 50MW sale to Cleveland Public Power beginning in 1996 and a 200MW sale over 15 years to the North Carolina Electric Membership Corp., also beginning in 1996. Further competitive gains are expected.

While operations have been superior, management's regulatory relations have been confrontational in the past, sometimes to the detriment of investors. However, under the leadership of Linn Draper, regulatory relations are expected to be less adversarial. Management's commitment to credit quality is overshadowed by efforts to enhance shareholder value, as evidenced by high debt leverage and a relatively high common dividend payout.

With limited domestic growth in AEP's core regulated domestic electric business, management will be more aggressive in nonregulated endeavors. For example, AEP management believes that future growth opportunities in various emerging markets are more attractive than the mature domestic market. The utility is exploring investing in China with the proposed building of two 1,300MW coal-

Regulation

Regulatory agency	Kentucky Public Service Commission
State	Kentucky
Case period	6
Interim procedures	Rarely.
Authorized returns (Last 12 to 18 months)	
Return on equity (electric)	11.5
Return on equity (gas)	11.5
Return on equity (telephone)	0
Rate base	Avg. original cost.
Test period	Forecasted.
CWIP	CWIP included in rate base for full cash return.
Adjustment mechanisms	Fuel and purchased power adjustment clauses (automatic), the energy component of purchased power is recovered through the fuel clause. The capacity component is recovered through base rates; gas cost adjustment clause permitted monthly based on actual costs for the second preceding month, with an under-/over-recovery mechanism included.
Incentive ratemaking	Rate of return.

Commissioners	Party	Term
George E. Overbey, Jr., Chair	Democrat	July 1995
Linda Breathitt	Democrat	July 1997
Robert M. Davis	Democrat	July 1996

Source: Regulatory Research Associates Inc.

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fired units at an estimated cost of $2 billion. AEP may add debt at the parent level to support its potential China investment.

In addition, management may be biding its time while waiting for the region's frail electrics to crater. Regardless, a strong operational base gives AEP management flexibility and options in this rapidly changing business environment.

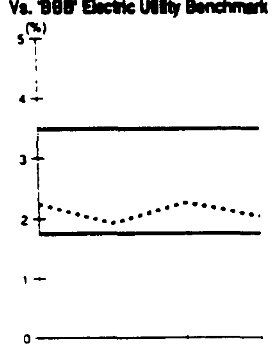
EARNINGS ANALYSIS For the first six months of 1995, earnings decreased 17.5% to $10.4 million compared with year-earlier earnings of $12.6 million. Lower earnings largely reflected reduced sales as a result of milder weather and an increase in interest expense because of additional debt.

In 1994, Kentucky Power's earnings increased 40.2% or $7.2 million because of favorable weather in the first half of 1994 and reduced AEP system power pool capacity charges. Going forward, earnings will heavily depend on retail sales growth and management's ability to control costs. Forecasted retail sales growth of about 1.4% annually should permit modest earnings improvement. However, heavy external funding requirements will result in higher debt and interest expense levels, which will place downward pressure on earnings protection measures. Pretax interest coverage is projected to be in the 2.0 times (x) to 2.2x range during the next five years compared with the current level of 2.03x as of June 30, 1995. The company's recent issue of junior subordinated deferrable interest debentures was given partial preferred equity treatment, which will help maintain adjusted interest coverages.

CASH FLOW ANALYSIS Cash construction expenditures for 1995-1999 are budgeted at approximately $273 million, which is a relatively high level given no new major plant construction. Depreciation and amortization over the same period is forecasted at about $136 million. Over the next five years, capital spending will average a relatively high 8.5% of total capitalization.

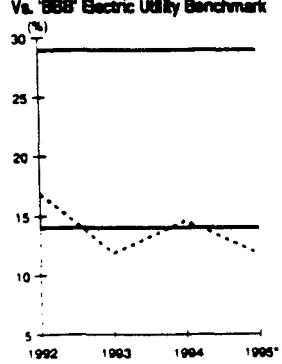
Net cash flow will cover only a relatively small 25% of planned capital spending through 1999. Funds from operations interest coverage will be under downward pressure as a consequence of heavy external funding needs and higher projected debt levels with resulting greater interest expense. Thus, projected adjusted funds from operations interest coverage is expected to range from 2.60x to 2.80x com-

Adjusted Pretax Interest Coverage Vs. 'BBB' Electric Utility Benchmark



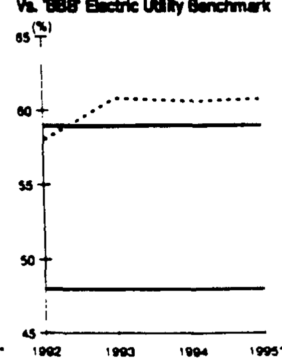
*For 12 months ended June 30 (unaudited).

Adjusted FFO/Avg. Total Debt Vs. 'BBB' Electric Utility Benchmark



*For 12 months ended June 30 (unaudited).

Adjusted Total Debt/Total Capital Vs. 'BBB' Electric Utility Benchmark



*For 12 months ended June 30 (unaudited).

pared with the current level of 2.62x as of June 30, 1995. In addition, funds from operations to average adjusted debt should range from 12% to 14% during the next five years compared with the current level of 11.7%.

BALANCE SHEET ANALYSIS

At June 30, 1995, adjusted debt leverage was at a liberal 60.8%, which was relatively high compared with other AEP operating units. However, Kentucky Power had no preferred stock. In April 1995, the company issued $40 million of 8.72% junior subordinated deferrable interest debentures due 2025. Proceeds from this offering were used to pay down short-term debt. This issue was given partial preferred equity treatment for analytical purposes by Standard & Poor's. Such treatment and planned equity infusions by AEP should result in an adequate capital structure.

Credit ratings are predicated on maintenance of a balanced capital structure, which will require meaningful equity infusions from parent AEP during the next five years. Standard & Poor's believes that Kentucky Power will not be able to reduce debt leverage materially over the next five years given external funding needs.

Financing flexibility

Common equity characteristics as of June 30, 1995	
Ticker symbol	AEP
Stock price ($)	34.250
PE ratio (x)	13.0
Dividend yield (%)	7.0
Market to book (%)	149.3
Dividend to book (%)	10.5

Debt characteristics at fiscal year ended 1994	
Secured debt (%)	100
Unsecured debt (%)	0
Subordinated debt (%)	0
Fixed-rate debt (%)	100
Variable-rate debt (%)	0
Avg. life of long-term debt (years)	12
Embedded cost of long-term debt (%)	7.6
Debt maturing in five years (mil. $)	65.0

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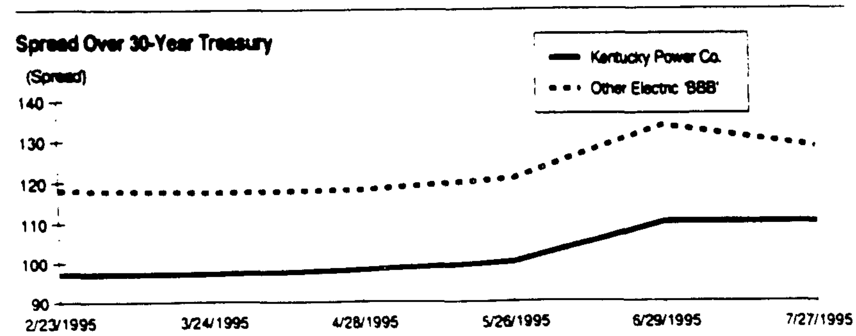
Short-term financing
As of March 31, 1995

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	0.0	52.2			
Bank lines					
Contracted committed lines	500.0	6.7	12/95	Yes	N.A.
Avg. cost of short-term debt (%)	6.2				

MAC—Material adverse change. N.A.—Not available.



Financial statistics

Kentucky Power Co.	1995*	1994	1993	1992	1991
	—Year ended Dec. 31—				
Income statement (mil. $)					
Gross revenues	302.3	307 4	294 3	313 2	306 8
Operating expenses (excl DD&A)	231.9	235.7	231 8	241 8	229.5
Depreciation and amortization	23.7	23.0	22.3	21 6	21 0
Pretax operating income	46.7	48.7	40 2	49.8	56 4
Gross interest expense	22.7	21.2	21 0	22.3	22.3
Pretax income	24.0	27.5	19.7	28.0	34 :
AFUDC and deferrals	0.5	0.5	0.3	0 4	0 4
Income taxes	0 9	2.2	1 6	1 5	5 7
Net income from continuing operations	23.0	25.3	18.0	26.5	28 5
Earnings protection					
Pretax interest coverage (x)	2.04	2.27	1.92	2.23	2.51
Adjusted pretax interest coverage (x)	2.03	2.26	1.91	2.23	N.A
Preferred dividend coverage (x)	2.04	2.27	1.92	2.23	2.51
AFUDC and deferred income/earnings (%)	2.1	1.9	1.5	1.5	1 3
Return on common equity (nominal) (%)	11.1	12.5	9.2	13.5	14 7
Common dividend payout (%)	96.1	84.7	125.8	80.5	71 9
Annual O&M growth (%)	(0.6)	5.7	16.6	(2.0)	N.A.
Annual expense growth (excl. DD&A) (%)	(1.6)	1.7	(4.1)	5.4	N.A.
O&M/revenues (%)	23.4	23.2	22.9	18.4	19.2
Total operating expenses (excl. DD&A)/revenues (%)	76.7	76.7	78.8	77 2	74 8
Balance sheet (mil. $)					
Cash and equivalents	0.9	0.9	0.9	1 1	0.9
Gross plant	864.0	851.9	807.4	780.9	756.7
Net plant	598.4	591.9	558.8	542.5	530.5
Total assets	744.4	714.3	670.4	616.7	611 9
Short-term debt	56.3	57.0	39.7	71.9	53.5
Long-term debt	263.0	261.7	260.1	203.5	224.1
Preferred stock	0.0	0.0	0.0	0.0	0 0
Common equity	207.3	208.4	194.5	199.2	194.0
Total capitalization	526.6	527.0	494.3	474.6	471.6
Total off-balance-sheet obligations	2.1	2.1	2.1	0.0	N.A.
Balance sheet ratios (%)					
Short-term debt/total capital	10.7	10.8	8.0	15.2	11.3
Long-term debt/total capital	49.9	49.6	52.6	42.9	47 5
Preferred stock/total capital	0.0	0.0	0.0	0.0	0 0
Common equity/total capital	39.4	39.5	39.3	42.0	41.1
Adjusted total debt/total capital	60.8	60.6	60.8	58.0	N.A.
Cash flow (mil. $)					
Net income	23.0	25.3	18.0	26.5	28.5
Depreciation	23.8	23.1	22.4	21.7	21.1
Deferred taxes and ITC	(3.0)	(2.7)	(1.8)	(4.5)	(2.8)
AFUDC and deferrals	(0.5)	(0.5)	(0.3)	(0.4)	(0.4)
Other FFO adjustments	(5.9)	(0.2)	(4.4)	3.3	(3.2)
Funds from operations (FFO)	37.4	45.0	34.0	46.6	43.2
Preferred dividends	0.0	0.0	0.0	0.0	0.0
Common dividends	(22.2)	(21.4)	(22.7)	(21 4)	(20.5)
Net cash flow (NCF)	15.3	23.6	11.3	25.3	22.9
Working capital changes	(7.1)	0.9	2.7	6.7	(8.3)
Capital expenditures (capex)	(47.8)	(52.6)	(35.0)	(31.3)	(28.8)
Discretionary cash flow	(39.6)	(28.2)	(21.0)	0.7	(14 4)
Cash flow adequacy					
Capex/avg. total capital (%)	9.1	10.3	7.2	6.6	6.1
NCF/capex (%)	32.0	44.8	32.2	80.8	78.9
FFO/avg. total debt (%)	11.7	14.5	11.8	16.9	15.6
Adjusted FFO/avg. total debt (%)	11.8	14.6	11.9	16.9	N.A.
FFO interest coverage (x)	2.62	3.09	2.52	3.03	2.87
Adjusted FFO interest coverage (x)	2.62	3.09	2.53	3.03	N.A.

N.A.—Not available. *For 12 months ended June 30 (unaudited). AFUDC—Allowance for funds used during construction. O&M—Operations and maintenance. DD&A—Depreciation, depletion, and amortization. ITC—Investment tax credits.

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Regulatory assets at year-end 1994 were a modest $5.3 million excluding $45.2 million due from customers for future federal income taxes. Regulatory assets are expected to be recovered in future periods through the ratemaking process.

FINANCIAL FLEXIBILITY Kentucky Power has adequate financing flexibility given its membership in the AEP family. At Dec. 31, 1994, unused short-term lines of credit shared with AEP system companies of $558 million were available. However, PUHCA provisions limit short-term borrowing to $100 million. At year-end 1994, Kentucky Power's outstanding short-term borrowings amounted to about $38.2 million. Periodic reductions of outstanding short-term debt are made through issuance of long-term debt and equity capital contributions by parent AEP.

In April 1995, Kentucky Power issued $40 million of 8.72% junior subordinated deferrable interest debentures due 2025 and used the proceeds to reduce short-term debt.

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KESI's (2nd Set)
Supplemental Request for Information
Item No. 17

Last Week's Ratings Reviews

of Avista Advantage Inc. and Avista Energy Inc. to provide energy services and energy marketing, respectively, should provide incremental earnings opportunities.

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AEP Generating Co.
Action: Ratings affirmed
Ranking: Not ranked
Business profile: N.A.

Appalachian Power Co.
Corporate credit rating: A-/Stable/—
Action: Ratings affirmed
Ranking: Below Columbus Southern Power Co. and above Atlantic City Electric Co.
Business profile: (4)

Columbus Southern Power Co.
Corporate credit rating: A-/Stable/—
Action: Ratings affirmed
Ranking: Below Ohio Power Co. and above Appalachian Power Co.
Business profile: (4)

Indiana Michigan Power Co.
Corporate credit rating: BBB+/Stable/—
Action: Ratings affirmed
Ranking: Below Hawaiian Electric Co and above Kentucky Power Co.
Business profile: (4)

Kentucky Power Co.
Corporate credit rating: BBB+/Stable/—
Action: Ratings affirmed
Ranking: Below Indiana Michigan Power Co. and above Puget Sound Energy Co.
Business profile: (4)

Ohio Power Co.
Corporate credit rating: A-/Stable/—
Action: Ratings affirmed
Ranking: Below Orange & Rockland Utilities Co. and above Columbus Southern Power Co.
Business profile: (4)

On July 31, the rating committee reviewed the American Electric Power Co. (AEP) system creditworthiness. Overall, from a credit standpoint, the AEP consolidated system is viewed as a strong 'BBB+'/weak 'A-' system. The rating committee continued to evaluate the AEP systems' business position as strong thanks to relatively low electric production costs, low electric rates compared with the region, efficient coal burning plants as evidenced by good heat rates, adequate generating reserve margins, the absence of base-load construction needs, and a strong transmission system. A higher business profile is restrained by strict regulatory environments and management's investments overseas. Overall, financials are adequate for the ratings. Liberal debt leverage and related fixed charge coverages are a limiting factor. On the other hand, cash flow is satisfactory based on projected capital spending plans.

In early 1997, AEP and Public Service Co. of Colorado (PSR) acquired the British regional electric distribution company (REC), Yorkshire Electricity Group PLC (AA/Watch Neg/A-1+) for $2.4 billion. Although AEP had the debt capacity to finance this acquisition without significant credit impact, this relatively large acquisition will restrain AEP's domestic financing flexibility and divert management attention. AEP plans to invest in China and other noncore markets, which offer long-term earnings potential, but also add risk. AEP may add debt at the parent level or provide strong support agreements to fund its China investments and other nonregulated generating investments, both domestically and internationally.

The rating committee affirmed Appalachian Power Co.'s ratings and outlook. Appalachian Power's adequate company-specific financial indicators should be sustainable in the absence of any stressful construction programs. Modest retail sales growth and cost control should support fixed-charge coverages and earned returns at satisfactory levels. Although Appalachian Power has negative reserve generating margins, ample power should be available from other AEP operating subsidiaries.

Columbus Southern Power Co.'s (CSPCo) ratings and outlook were affirmed. The company's financial profile continues to improve because of aggressive cost cutting and an attractive service territory. CSPCo has the most favorable retail sales growth prospects (2.7% annually) in the AEP system because of its heavy residential and commercial load. Unlike the other major AEP operating subsidiaries, CSPCo does not service a heavily industrialized area. CSPCo and its Ohio affiliate, Ohio Power, have combined their functional operations, which has resulted in significant cost savings and reduced future rate-relief needs. Although debt leverage is still high, CSPCo is structurally a low-risk utility in view of an attractive service territory, relatively low rates, and the absence of nuclear challenges. Ample power is available from other AEP operating units to cover CSPCo's negative reserve generating margins.

The rating committee also voted to maintain Indiana Michigan Power's credit ratings and stable credit outlook. Indiana Michigan's adjusted debt leverage is expected to continue at liberal levels. However, cash flow generation and cash interest coverage are expected to be adequate for current ratings. This AEP subsidiary owns the Cook nuclear units, which have operated at satisfactory levels.

Kentucky Power's Co.'s ratings and outlook also were affirmed. Still, Kentucky Power's interest coverage and capitalization ratios after adjusting for capacity payments associated with long-term contracted Rockport power purchases are weak, but are supported by the system's stronger financial condition. For the foreseeable future, projected Kentucky Power spending will require significant external funding which will pressure financials. Common equity infusions from parent AEP will be needed to maintain a balanced capital structure.

The rating committee also voted to affirm the ratings and credit outlook for Ohio Power Co. based on its debt-reduction plans, and continuing aggressive cost control. Ohio Power is one of the surplus power companies within the AEP system. Ohio Power is not only a large seller of power to deficit AEP companies, but also a large supplier of energy to other buyers in the region and a formidable competitive threat to the high-cost, high-rate electric utilities in the region.

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(continued on next page)

KENTUCKY POWER CO.

STEVE Z[illegible], NEW YORK (1) 212-2[illegible]

Credit Rating

Kentucky Power Co.

Corporate Credit Rating:
BBB+/Stable/—

RATIONALE The ratings on Kentucky Power Co. largely reflect the above average business profile and adequate financial position of parent American Electric Power Co. The American Electric Power system is physically interconnected, with management, operations, and financial policies coordinated at the parent level. Both Kentucky Power's stand-alone and American Electric Power's consolidated financials are expected to be relatively stable going forward.

Kentucky Power's creditworthiness is enhanced by its membership in the American Electric Power Co. system. The Kentucky Public Service Commission approved a settlement agreement providing for full recovery of costs associated with Rockport unit power purchases and transmission equalization payments. Previously, the Kentucky commission had limited recovery to the less expensive American Electric Power power pool embedded cost rate rather than the more costly Rockport unit power agreement. Still, Kentucky Power's interest coverage and capitalization ratios after adjusting for capacity payments associated with long-term contracted Rockport power purchases are weak, but are supported by the system's stronger financial condition. For the next five years, projected Kentucky Power spending will require significant external funding, which will pressure financials. Common equity infusions from parent American Electric Power will be needed to maintain a balanced capital structure.

American Electric Power system's internal funds generation and cash interest coverage are expected to remain adequate, although debt leverage continues to be aggressive. American Electric Power's challenges include increasing wholesale profitability, a cyclical industrial load, strict state rate regulation, and clean air requirements.

OUTLOOK Strong consolidated American Electric Power operations provide ratings stability and support for the maintenance of Kentucky Power's credit quality. Significant capital spending relative to Kentucky Power's size and cash flow generation capability will restrain credit improvement for this American Electric Power subsidiary. Clean air spending, purchased power, and lackluster projected retail sales growth add risk, but are reflected largely in ratings.

Kentucky Power Co. financial statistics

	—Year ended Dec. 31—				
(Mil. $)	1996	1995	1994	1993	1992
Gross revenues	323.3	328.1	307.4	294.3	313.2
Net income from continuing operations	20.5	25.1	25.3	18.0	26.5
Funds from operations (FFO)	38.7	48.0	45.0	34.0	46.6
Net cash flow (NCF)	11.0	22.4	23.6	11.3	25.3
Capital expenditures (capex)	75.8	38.9	52.8	35.0	31.3
Pretax interest coverage (x)	2.26	2.32	2.27	1.92	2.23
Preferred dividend coverage (x)	1.80	1.97	2.27	1.92	2.23
FFO interest coverage (x)	3.09	3.30	3.09	2.52	3.03
Capex/avg. total capital (%)	12.8	7.0	10.3	7.2	6.6
NCF/capex (%)	14.5	57.6	44.8	32.2	80.8
FFO/avg. total debt (%)	11.7	14.8	14.5	11.8	16.9
Return on common equity (nominal) (%)	7.3	10.5	12.5	9.2	13.3
Total capitalization	614.0	591.9	527.0	494.3	474.6
Short-term (%)	8.9	9.9	10.8	8.0	15.2
Long-term debt (%)	45.0	46.0	49.6	52.6	42.9
Preferred stock (%)	6.5	6.8	0.0	0.0	0.0
Common equity (%)	39.6	37.3	39.5	39.3	42.0

Kentucky Power Co. operating statistics

	1996	1995	1994	1993	1992
Total sales (GWh)	N.A.	10,342	9,281	8,916	9,811
Residential (%)	N.A.	21.2	21.8	22.1	19.2
Commercial (%)	N.A.	11.0	11.6	11.6	10.1
Industrial (%)	N.A.	28.8	30.9	31.3	28.7
Wholesale (%)	N.A.	38.9	35.6	34.9	41.8
Other (%)	N.A.	0.0	0.1	0.1	0.0
Avg. retail revenue (cents/kWh)	N.A.	4.17	4.19	4.18	4.36
Retail sales growth (%)	N.A.	5.69	3.02	1.68	(0.19)
Capacity at time of peak (MW)	N.A.	N.A.	24,067	23,810	24,202
Reserve margin (%)	N.A.	N.A.	24.1	30.6	37.1

N.A.-Not available. MW-Megawatts. MWh-Megawatt-hours. kWh-Kilowatt hours. GWh-Gigawatt hours.

(Continued from page 2)

Coupon	Type of Debt	Maturity	Moody's Rating
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	7.875% Cum. Pfd. Stk.		"baa1"
	7% Cum. Pfd. Shs.		"baa1"
	Commercial Paper		P-2
Indiana Michigan Power Company			
7.000%	First Mortgage Bonds	1998	Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Counterparty Rating		Baa2
7.250%	S.F. Debenture	1998	Baa2
	6.3% Cum. S.F. Pfd. Stk.	2009	"baa2"
	6.25% Cum. Pfd. Stk.	2009	"baa2"
	5.9% Cum. S.F. Pfd. Stk.	2009	"baa2"
	4.125% Cum. Pfd. Stk.		"baa2"
	4.12% Cum. Pfd. Stk.		"baa2"
	7.08% Cum. Pfd. Stk.		"baa2"
	6.875% Cum. Pfd. Stk.		"baa2"
	Commercial Paper		P-2
	415 Shelf Registration		(P)Baa1
Kentucky Power Company			
7.875%	First Mortgage Bonds	2002	Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	MTN Program		Baa1
	Counterparty Rating		Baa2
	Commercial Paper		P-2
	415 Shelf Registration		(P)Baa2
Ohio Power Company			
9.875%	First Mortgage Bonds	2020	A3
7.750%	First Mortgage Bonds	2002	A3
7.625%	First Mortgage Bonds	2002	A3
6.750%	First Mortgage Bonds	1998	A3
6.500%	First Mortgage Bonds	1997	A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
7.875%	S.F. Debenture	1999	Baa1
6.625%	S.F. Debenture	1997	Baa1
	Counterparty Rating		Baa1
	5.9% C[illegible] Pfd. Stk.	200[illegible]	"baa1"
	6.02% Cum. S.F. Pfd. Stk.	2008	"baa1"
	4.08% Cum. Pfd. Stk.		"baa1"
	4.20% Cum. Pfd. Stk.		"baa1"
	4.40% Cum. Pfd. Stk.		"baa1"
	4.50% Cum. Pfd. Stk.		"baa1"
	6.35% Cum. Pfd. Stk.		"baa1"
	Commercial Paper		P-2

Kentucky Power Company

	1995	1994	1993	1992	1991
Coverage Analysis (Excl. AFUDC and Other Allowances)					
Pretax interest coverage	2.24	2.33	1.97	2.33	2.64
SEC interest coverage	2.26	2.35	1.98	2.35	2.66
SEC fixed-charge coverage	2.26	2.35	1.98	2.35	2.66
Funds from oper.%interest exp.	2.82	2.88	2.82	2.95	2.93
Funds from oper.%net CAPEX (%)	113.42	75.52	109.69	138.53	149.28
Funds from oper.%net CAPEX + pref. div.	113.42	75.52	109.69	138.53	149.28
Funds from oper.%total debt (%)	13.80	12.41	12.82	15.99	15.78
Deferred charges as % of common equity	42.86	29.55	26.13	5.62	6.07
Earnings Analysis					
Return on avg.					
Common equity	11.72	12.55	9.16	13.50	14.98
Total assets	3.38	3.65	2.80	4.32	4.67
Total capital	7.20	7.20	6.58	8.66	9.12
AFUDC as % net income	1.46	1.91	1.47	1.55	1.06
Asset Composition					
Total assets	772.2	714.3	670.4	616.7	611.9
As % total assets					
Net utility plant	78.9	82.9	83.3	88.0	86.7
Investments	0.8	0.9	1.0	1.3	1.3
Current assets	8.0	7.6	8.1	8.9	10.1
Deferred charges	12.2	8.6	7.6	1.8	1.9
As % gross electric plant					
Electric plant in prod. (gross)					
Fossil	26.2	26.3	26.2	26.4	27.0
Total electric plant in prod.	26.2	26.3	26.2	26.4	27.0
Other electric plant (gross)					
Transmission	29.7	30.3	31.0	31.1	31.6
Distribution	35.7	35.0	34.9	34.2	33.6
Common plant	6.8	6.6	6.8	7.0	6.7
Construction in process	1.7	1.8	1.2	1.3	1.1
Total other electric plant	73.8	73.7	73.8	73.6	73.0
Construction					
Construction expenditures (excl. AFUDC)	39	53	35	31	29
CWIP % common equity	6.6	7.2	4.8	5.2	4.4
CWIP % gross plant	1.7	1.8	1.2	1.3	1.1
Constr. exp. % prior year cap.	7.4	10.7	7.4	6.7	6.5
Constr. exp. % prior yr. gross plant	4.6	6.5	4.5	4.1	3.9

Kentucky Power Company	1995	1994	1993	1992	1991
Market Analysis					
Total operating revenue	328.1	307.4	294.3	313.2	306.8
As % total oper. revenue					
Electric	100.0	100.0	100.0	100.0	100.0
As % total electric revenue					
Residential	32.8	32.7	33.1	30.8	31.7
Commercial	17.9	18.2	18.3	17.1	17.5
Industrial	29.5	30.2	30.8	31.3	32.5
Public authority	0.3	0.3	0.3	0.3	0.3
Wholesale	18.5	17.5	16.4	19.6	16.9
Other	1.2	1.1	1.1	0.9	1.1
KWH Sales	10,342	9,281	8,916	9,811	8,647
As % total KWH sales					
Residential	21.2	21.8	22.1	19.2	21.9
Commercial	11.0	11.6	11.6	10.1	11.4
Industrial	28.8	30.9	31.3	28.7	32.6
Other	0.1	0.1	0.1	0.1	0.1
Wholesale	38.9	35.6	34.9	41.8	33.9
Average revenue per KWH (cents)					
Residential	4.91	4.97	4.94	5.12	5.13
Commercial	5.16	5.21	5.21	5.41	5.44
Industrial	3.24	3.24	3.25	3.47	3.54
Wholesale	1.50	1.63	1.55	1.49	1.77
Peak Load Analysis					
Summer (MW)					
Generating capacity	1,450	1,450	1,450	1,450	23,829
Firm purchases	0	0	0	0	439
Less sales	0	0	0	0	871
Peak load	1,465	1,515	1,340	1,216	17,556
Summer excess capacity	-15	-65	110	234	5,841
Winter (MW)					
Generating capacity	1,450	1,450	1,450	1,450	24,084
Purchases	0	0	0	0	358
Less sales	0	0	0	0	871
Peak load	1,512	1,575	1,316	1,364	16,538
Winter excess capacity	-62	-125	134	86	7,033
Reserve margins					
Summer	-1	-4	8	19	33
Winter	-4	-8	10	6	43

Kentucky Power Co.

Ashland, Kentucky, USA

Ratings

Category	Moody's Rating
Senior Secured MTN	Baa1
Counterparty Rating	Baa2
Junior Subordinated	Baa3
Commercial Paper	P-2

Contacts

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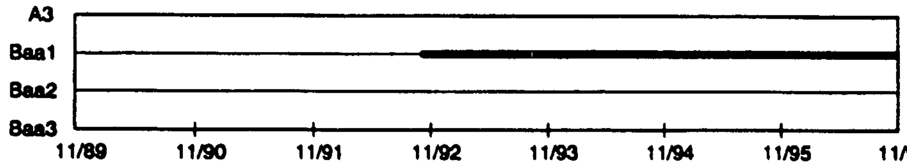
Susan D. Abbott	

American Electric Power Company, Inc.

Commercial Paper	P-2

Rating History



Operating Statistics

Kentucky Power Company (Statistics in bold type)
Peer Group Median (Statistics in light type)

	[1]1996	1995		1994		1993		1992		[2]5-Yr.Avg.	
Revenue (US$ bil.)	**0.3**	1.0	**0.3**	1.0	**0.3**	1.0	**0.3**	0.9	**0.3**	[3]4.1	**[3]2.2**
Assets (US$ bil.)	**0.8**	2.8	**0.8**	2.7	**0.7**	2.6	**0.7**	2.4	**0.6**	[3]4.4	**[3]4.9**
Com. Equity (US$ bil.)	**0.2**	0.9	**0.2**	0.8	**0.2**	0.7	**0.2**	0.7	**0.2**	[3]5.5	**[3]3.5**
Op. Margin (%)	**16.5**	21.9	**16.7**	21.5	**16.2**	20.7	**14.0**	21.4	**16.5**	21.5	**16.5**
ROA (avg.)(%)	**3.1**	3.8	**3.4**	3.5	**3.7**	3.7	**2.8**	3.8	**4.3**	3.8	**3.8**
ROE (avg.)(%)	**11.0**	12.7	**11.7**	11.7	**12.5**	12.0	**9.2**	11.9	**13.5**	12.1	**12.4**
Div. Payout (%)	**98.7**	79.3	**91.2**	83.5	**84.7**	81.5	**125.8**	81.9	**82.7**	81.2	**91.3**
Pretax Int. Cov. (X)	**2.3**	3.4	**2.2**	3.3	**2.3**	3.2	**2.0**	2.9	**2.3**	3.1	**2.3**
Fxd. Chg. Cov. (X)	**2.3**	2.9	**2.3**	2.7	**2.4**	2.6	**2.0**	2.4	**2.4**	2.6	**2.3**
RCF % TD	**6.2**	15.0	**6.6**	14.3	**5.7**	13.1	**5.2**	12.8	**8.1**	13.7	**6.8**
RCF % Gross CAPEX	**51.8**	113.6	**54.0**	89.5	**34.6**	90.6	**44.5**	87.2	**69.3**	94.4	**55.9**
Total Cap. (US$ bil.)	**0.6**	1.9	**0.5**	1.8	**0.5**	1.8	**0.5**	1.7	**0.5**	[3]3.9	**[3]3.9**
TD % Cap.	**60.0**	49.5	**59.2**	50.0	**60.6**	50.4	**60.6**	50.0	**57.6**	50.1	**59.3**
Pfd. Stk. % Cap.	**0.0**	5.7	**0.0**	6.3	**0.0**	6.2	**0.0**	6.6	**0.0**	6.3	**0.0**
Common % Cap.	**40.0**	45.0	**40.8**	44.3	**39.4**	44.3	**39.4**	43.2	**42.4**	43.9	**40.7**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	107.5	58.6	96.6	60.6
Kwh(mil.)	2,192	1,135	2,980	4,025
¢/Kwh	4.9	5.2	3.2	1.5
Industry Avg. (¢/Kwh)	8.6	7.4	5.2	3.3
Competitive Position	**Break-even Price($)**	**Regional Avg.($)**	**Stranded Cost($mil.)**	**Stranded Cost % Eq.**
	5.41	51.93	0	0

[1] For the 12 months ended June 30; Balance sheet items are as of June 30. [2] Five year average 1995-1991. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

Kentucky Power Company's (KP) Baa1 senior secured rating reflects the benefits of membership in the American Electric Power (AEP) system, the company's very competitive generating costs, and its low Clean Air Act compliance costs. However, the rating also reflects the company's highly leveraged balance sheet, large percentages of industrial and wholesale customers, and generating asset concentration.

The 1,060 mw, coal-fired Big Sandy plant represents 73% of KP's capacity. This owned capacity is supplemented by a long-term contract to purchase 390 mw from the AEP system's Rockport plant. These purchases represent a substantial off-balance-sheet obligation, which when fully reflected on the balance sheet, exacerbates an already weak capital structure (75% adjusted leverage).

The company expects that over the next five years internal cash flow will meet only one-third of capital expenditures, most of which are needed to improve transmission. The company will rely on parent support and on the capital markets to meet the balance of its spending needs.

Rating Outlook

We view KP's credit ratings as stable. We believe that the intercompany nature of KP's power purchases and AEP's support of this small subsidiary substantially offset the risks of a financial profile weaker than the industry norm.

Moody's Investors Service
Global Credit Research

American Electric Power Company, Inc.

December 1996

Category	Moody's Ratings
Appalachian Power Company	A3
Columbus Southern Power Company	A3
Indiana Michigan Power Company	Baa1
Kentucky Power Company	Baa1
Ohio Power Company	A3

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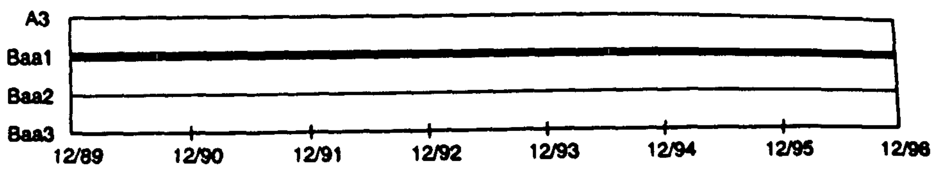

American Electric Power Company, Inc.

	[1]1996	1995	1994	1993	1992	[2]5-Yr.Avg.
Revenue (US$ bil.)	5.9	5.7	5.5	5.3	5.0	[3]1.9
Assets (US$ bil.)	15.9	15.9	15.7	15.3	14.2	[3]2.6
Com. Equity (US$ bil.)	4.4	4.3	4.2	4.2	4.2	[3]0.8
Op. Margin (%)	22.7	22.1	21.2	21.9	19.9	21.6
ROA (avg.)(%)	3.6	3.4	3.2	2.4	3.3	3.2
ROE (avg.)(%)	13.3	12.4	11.9	8.4	11.1	11.1
Div. Payout (%)	73.7	84.1	88.6	125.2	94.6	96.3
Pretax Int. Cov. (X)	3.3	3.1	2.9	2.8	2.3	2.7
Fxd. Chg. Cov. (X)	2.3	2.2	2.1	2.0	2.0	2.1
RCF % TD	12.8	13.7	8.0	8.7	9.5	9.6
RCF % Gross CAPEX	148.9	124.6	66.9	78.8	84.3	85.3
Total Cap. (US$ bil.)	11.4	10.5	10.4	10.3	10.6	[3]0.9
TD % Cap.	55.3	52.5	51.6	52.0	52.6	52.3
Pfd. Stk. % Cap.	5.6	6.3	7.9	7.5	7.2	7.1
Common % Cap.	39.1	41.2	40.5	40.5	40.2	40.6
Adj. TD % Adj. Cap.	43.4	51.8	51.8	51.1	51.9	51.9

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	1,953.9	1,265.8	1,606.5	680.9
Kwh(mil.)	30620	22190	44367	22238
¢/Kwh	6.4	5.7	3.6	3.1

[1] For the 12 months ended June 30: Balance sheet items are as of June 30. [2] Five year average 1995-1991. [3] Five year compound annual growth rate.

Rating Rationale

The A3 and Baa1 ratings for American Electric Power's (AEP) utilities are based on the system's strong competitive position. The ratings also reflect generally modest service territory growth and leverage that is above industry norms as the result of only moderate regulatory support in many jurisdictions.

AEP's sales are concentrated in the industrial sector, which contributed 45% of 1995 retail sales. As the electric utility industry evolves towards open price competition, the threat of customer loss is higher among this class than any other. However, we believe that AEP's average 1995 industrial rate of 3.62 cents per kwh, substantially lower than the national average of 4.86 cents, will allow the company to compete aggressively to maintain and even improve market share.

The system's 87% coal-fired generating capacity required substantial Clean Air Act (CAA) compliance costs, which are being recovered through retail rates and system power pool sales. Modest environmental compliance costs will be incurred over the next five years, primarily to complete nitrogen oxide modifications on boilers. Other capital expenditures are also manageable as the AEP power pool system will allow members to defer construction of additional generating capacity beyond 2000.

AEP is expanding investment in non-re[illegible] gy-related ventures both overseas and in [illegible] expect these investments to have minimal [illegible] the operating utilities' ratings due to their mod[illegible] in relation to the size of the company.

Rating Outlook

The rating outlooks for AEP's subsidiaries are st[illegible]

American Electric Power Company, Inc.

In-Depth Analysis

Coupon	Type of Debt	Maturity	Moody's Rating
American Electric Power Company, Inc.			
	Commercial Paper		P-2
Appalachian Power Company			
8.000%	Sr. Sec. Medium-Term Notes	2025	A3
8.000%	Sr. Sec. Medium-Term Notes	2005	A3
7.850%	Sr. Sec. Medium-Term Notes	2004	A3
	Counterparty Rating		Baa1
9.875%	First Mortgage Bonds	2020	A3
6.800%	First Mortgage Bonds	2006	A3
7.500%	First Mortgage Bonds	2002	A3
7.625%	First Mortgage Bonds	2002	A3
6.375%	First Mortgage Bonds	2001	A3
7.500%	First Mortgage Bonds	1998	A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	5.9% Cum. Pfd. Stk.	2008	"baa1"
	6.85% Cum. Pfd. Stk.	2004	"baa1"
	4.5% Cum. Pfd. Stk.		"baa1"
	4.5% Cum. Pfd. Stk.		"baa1"
	7.4% Cum. Pfd. Stk.		"baa1"
	7.80% Pfd. Stk.		"baa1"
	5.92 % Cum. Pfd. Stk.		"baa1"
	Commercial Paper		P-2
	415 Shelf Registration		(P)A3
	415 Shelf Registration		(P)Baa1
Columbus Southern Power Company			
7.600%	Sr. Sec. Medium-Term Notes	2024	A3
7.450%	Sr. Sec. Medium-Term Notes	2024	A3
6.750%	Sr. Sec. Medium-Term Notes	2004	A3
6.550%	Sr. Sec. Medium-Term Notes	2004	A3
	Counterparty Rating		Baa1
7.000%	First Mortgage Bonds	1998	A3
6.250%	First Mortgage Bonds	1997	A3
	Secured MTN Program		A3
	Secured MTN Program		A3

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Company Fundamentals

Business Fundamentals and Competitive Position

American Electric Power Company (AEP) is one of 11 registered utility holding companies regulated by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. AEP is a system of five large electric utilities, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company; two small, unrated utilities; and one wholesale electric generating company, AEP Generating Company. In 1996 the entire AEP system began serving its customers under the brand name "American Electric Power," although the utilities retain their separate legal existence and indentures. Table 1 details the size and market characteristics of the five rated utilities.

Table 1: 1995 UTILITY OVERVIEW

	AP	CSP	I&M	KP	OP
Operating Revenues ($000,000)	1,545	1,072	1,283	328	1,823
Sales as % of Retail Sales:					
Residential	38	38	32	35	21
Commercial	21	39	27	18	15
Industrial	38	20	41	47	64
Wholesale as % of Total Sales	26	16	48	39	31
Service Territory	VA, WV	OH	IN, MI	KY	OH
Retail Customers	859,000	599,000	537,000	165,000	668,000
Competitive Position	Above Aver	Average	Average	Above Aver	Above Aver

The System

The five large utilities (the "member utilities") benefit from their membership in the AEP system pool through cost sharing and the deferral of construction of new capacity. The parent, which has little debt at the holding company level and to date very modest investment plans in non-regulated businesses, can also manage the capital structure of a subsidiary to a modest degree through capital contributions and upstreamed dividends. These advantages of financial and operating flexibility currently have a small positive impact on ratings relative to what the ratings of each individual utility on a stand-alone basis might be.

AEP operates the member utilities' 23,759 megawatts of generating capacity as a power pool under an economic dispatch system, 85.6% coal-fueled, 10.9% nuclear-fueled, and less than 1% hydro-powered. A member that sells more power to its retail customers than it has capacity to produce becomes a net purchaser from the pool. Net purchasers (Appalachian Power and Columbus Southern) compensate the sellers (Ohio Power, Indiana Michigan, and, to a small extent, Kentucky Power) for the seller's embedded costs, including capacity, operations, maintenance, and fuel. Table 2 illustrates the revenue and cost sharing resulting from the five members' participation in interconnection, transmission, and system wholesale power sales agreements.

Table 2: 1995 SHARED COSTS AND CREDITS ($000)

Subsidiary	Generation	System Wholesale Power Sales	Power Pool Transmission	Transmission for Non-Affiliated Companies
AP	(252,000)	24,100	(5,400)	6,000
CSP	(143,000)	12,000	(31,100)	4,200
I&M	118,000	34,700	46,700	4,800
KP	23,000	5,000	3,500	1,200
OP	217,000	20,200	(13,700)	17,800

Although the sellers earn no return on sales to the pool, the system benefits from the power pool arrangement as it allows the members to defer construction of additional generating capacity beyond what otherwise might have been needed.

Under current projections, AEP will not need new capacity until after 2000. The summer peak reserve margin fell from 22.3% in 1994 to 15.8% in 1995 due to growth in peak demand and the firm sale of capacity to non-affiliated utilities. The company estimates a narrower weather-normalized reserve margin of 11% on the 1999-2000 horizon due to estimated peak demand growth of 1.1% per year over the next five years compared to 2.7% over the past five years. The company estimates that retail sales will grow 1.9% over the next five years, slower than the 3.1% pace of the past five years. As competition increases, many industry participants view as appropriate a lower standard than the 15-20% reserve margin range commonly accepted as prudent in ratemaking proceedings across the nation. That changing standard is another reason AEP is able to postpone construction of additional capacity.

Moody's estimates that only Columbus Southern and Indiana Michigan face potential stranded costs, which are detailed below. Moody's views these two utilities' stranded costs as manageable and also mitigated by the cost advantages provided by the other three member utilities.

Wholesale sales to non-affiliated utilities comprised 18% of consolidated sales in 1995. AEP, interconnected with 29 neighboring utilities at 142 sites, has pursued new markets outside its service territory. The company won a 15-year contract to supply 200 megawatts of power to the North Carolina Electric Membership Corporation beginning in 1996 and added a 50 megawatt, five-year contract which began in September 1996 to supply power to Cleveland Public Power. Contracts presently total 1320 megawatts. We expect that the system's wholesale power sales will grow to the extent that it can source cost-effective wholesale power and utilize its extensive transmission network. While total wholesale revenues arise primarily from the more volatile short-term sales, reflecting weather patterns, the AEP system is building a small, but growing stream of revenues from long-term contracts.

We believe that AEP's generation and transmission systems will be among the most competitive in the deregulating industry. Declining fuel costs have offset slightly higher non-fuel operating and maintenance costs over the past few years, resulting in total production costs in the 2.0-2.1 cents per kilowatthour range. The production cost advantage allows the company to offer competitive rates. For 1995, the company's rates in the fiercely competitive industrial sector averaged 3.62 cents per kilowatthour compared to the national average of 4.86 cents. The utilities individually have competitive positions of average to above-average, as discussed below and as demonstrated in Table 3.

The Subsidiaries

APPALACHIAN POWER COMPANY (AP) — AP contributes 26% of AEP's operating revenues. AP uses its 5,853 megawatts (mw) of mostly coal-fired, highly competitive generating capacity and purchased power to serve customers in Virginia and West Virginia. The company estimates retail sales growth of 2.2% over the next five years, a somewhat slower pace than the 3.1% growth rate of the past five years. The economy in the Virginia portion of the service area is expected to be stronger than that of the West Virginia service area. Industrial customers, which represent 38% of the company's retail sales, include primary metals, chemicals, textiles, paper, and coal mining companies. AP's 1995 industrial rate of 3.68 cents was well below the national average of 4.86 cents.

AP's wholesale sales, which represent 26% of total sales, are to other non-affiliated utilities, and to an affiliated non-pool-member, Kingsport Power. Reflecting the impact of the Federal Energy Regulatory Commission's open access Order 888, customers have given notice of termination for nearly three-quarters of total demand on contracts maturing in up to four years. We anticipate that AP will be able to retain some of this load and that the loss of some of these contracts will have little impact on the company's margins as it is a net purchaser of power from the AEP system.

COLUMBUS SOUTHERN POWER COMPANY (CSP) — CSP contributes 20% of AEP's total operating revenues. CSP's sales to the robust Columbus commercial sector account for 39% of CSP's retail sales. Industrial sales account for only 20% of retail sales and are spread across a number of industries. The company's industrial rates are about equal to the national average. The company estimates that retail sales will grow 2.6% per year over the next five years, slightly above the national average and at a slower rate than the 3.8% over the past five years. Regional unemployment is expected to remain below national levels.

CSP's 2,595-mw generating capacity is completely coal-fired. The nuclear-to-coal conversion of the Zimmer plant, which is jointly owned with two unaffiliated utilities, was completed in 1991. While the Zimmer plant is among the most efficient in its region, Moody's estimates that CSP's stranded costs equal 70% of equity, primarily attributable to the fixed costs associated with the Zimmer investment. Zimmer's costs are reflected in current rates. Moody's expects these stranded costs to be manageable given their magnitude and the other competitive advantages of the AEP system.

INDIANA MICHIGAN POWER COMPANY (I&M) — I&M contributes 19% of the AEP system's revenues. Indiana accounts for 82% of the utility's retail sales, with the other 18% in Michigan. Industrial sales account for 41% of total retail sales, with concentrations in primary metals, electrical machinery, transportation equipment, chemicals, and fabricated metals. Reflecting a healthy local economy, the company expects retail sales to grow 2.9% per year over the next five years, only slightly slower than the 3.3% annual growth of the previous five-year period.

I&M's competitive position is average due to its generating cost and rate structures. Its industrial rates equal the regional average. The two Cook nuclear units represent 47% of I&M's 4,434 megawatts of generating capacity, and nearly all of the balance is coal-fired. Based upon 1995 data, Moody's estimates I&M's stranded costs at a manageable 41% of equity, substantially improved from the prior year due to lower operating costs at the Cook units. Refueling outage duration has declined in recent years from 106 days to the most recent outage duration of 48 days. AEP has taken further steps to lower operating costs by consolidating nuclear management at the nuclear plant site.

Off-system sales, which comprised 48% of total sales in 1995 and which include wholesale sales made to the pool, are important to I&M's financial health. I&M and AEP Generating Company each have a 50% interest in both Rockport units, whose total capacity is 2600 mw. (Rockport 2, which went into commercial operation in 1989, is financed through an operating lease.) I&M purchased an additional 455 mw of Rockport capacity from AEG. I&M has sold 250 mw of its total Rockport capacity to an unaffiliated utility under a long-term contract expiring in 1999. I&M uses the remaining 1505 mw to meet its retail and power pool demand. I&M's highly volatile off-system sales account for a shrinking percentage of total revenues, offset by the increase in more profitable retail sales.

KENTUCKY POWER COMPANY (KP) — KP is the smallest of the member utilities, contributing 5% of revenues. It has one generating source, the 1,060-mw Big Sandy plant. Although it is a net seller to the power pool, purchased power costs totaled 37% of the utility's operating and maintenance costs in 1995, including purchases from AEP Generating. Still, the utility's competitive position is above both regional and national averages as a result of its low generating cost structure and reasonable rates. As a result, we expect the company to retain its industrial customer base, which is concentrated in petroleum, primary metals, and chemicals, and which accounts for 47% of total retail sales. The company anticipates retail sales growth of 2.1% per year over the next five years, down only slightly from the 2.7% per year of the past five years.

OHIO POWER COMPANY (OP) — OP accounts for 27% of AEP's revenues, the highest share among the system's member utilities. The utility is also the largest net seller of power to the system power pool. Its 8,464-mw generation capacity serves not only its own retail customers in Ohio, but also wholesale customers, which, including the AEP power pool, comprise 31% of sales. Retail sales, which have grown an average of 3.0% per year over the last five years, will slow to the very modest rate of 0.7% per year, the lowest growth rate of the five utilities. Industrial customers, which contribute 64% of retail sales, are heavily concentrated in primary metals, but also include such industries as petroleum, rubber, plastics, stone, clay, glass, chemicals, transportation equipment, and electrical machinery. Although competition is fierce in the industrial sector, OP's low industrial rates, which average 3.19 cents per kilowatthour compared to the national average of 4.86 cents, provide a strong competitive edge.

Expiration of two major industrial contracts, Ormet Corporation in 1997 and Ravenswood Aluminum in 1998, which together account for 890 mw of demand, is cause for only modest concern despite OP's low growth rate and high reserve margins. The Ormet contract was extended through 1999, at which time an alternate supplier may replace Ohio Power. The contract with Ravenswood was extended through 2003. Both contracts currently entail low margins. Moody's expects retail sales growth within the AEP system, growing system wholesale contracts, and retention of associated transmission revenues to offset potential loss of this demand.

Table 3: 1995 RATE COMPARISONS

Company	Industrial	Commercial	Residential
AP	3.68	5.14	5.68
CSP	4.79	6.41	7.88
I&M	4.53	5.96	6.76
KP	3.24	5.16	4.91
OP	3.19	5.46	6.48
AEP System	3.62	5.70	6.38
ECAR Average	4.66	6.90	7.87
National Average	4.86	7.85	8.83

Source: RRA and Moody's

AEP GENERATING COMPANY — AEP Generating Company generates and sells power at wholesale from Rockport Units 1 and 2, in which AEP Generating and I&M each have a 50% interest. Unit 1 is owned, and Unit 2 is leased. KP purchases 30%, or 390 mw, of AEP Generating's share of the power generated by each Rockport unit under a contract expiring at the end of 1999. An unaffiliated utility purchases 70%, or 455 mw, of AEP Generating's share of power available from Rockport Unit 1 through the end of 1999. The remaining portion of AEP Generating's share of Unit 2 is sold to I&M. AEP Corporation (the parent) provides financial support to AEP Generating under a capital funds agreement, ensuring that it will be able to meet any financial obligations.

OTHER SUBSIDIARIES — AEP established AEP Resources to invest in non-regulated power projects around the globe and in foreign utility companies. No investments in the U.S. have been made so far under a strategic alliance among AEP, Cogentrix Energy, and Zurn Industries to develop, own, and operate industrial projects in the U.S. and Canada. Resources' first international project is a joint venture to build a $172 million, coal-fired electric generating plant in China. Other countries targeted by AEP for consideration are Australia, Mexico, and India. AEP also established a subsidiary offering energy consulting and management services as well as a power marketing subsidiary which has FERC approval to market wholesale power at market-based rates to customers beyond AEP's retail service territory and the service territories of those utilities directly connected to the AEP system.

Management Strategy

AEP management's strategy derives from the company's large, low-cost operations within the U.S. Although the company is pursuing international investment in the energy arena, its international efforts are modest in relation to its size. It focuses mainly on the U.S. energy markets, both within and beyond the present service territory. Management supports full consumer choice of energy suppliers, as first publicly announced in October of 1995. They also support recovery of stranded costs, a limited issue for AEP, but a significant one in the larger state jurisdictions within their service territory. AEP has also spearheaded the creation of the Midwest Independent System Operator (ISO), an organization intended to centrally manage an extended multi-state transmission grid with major goals of reliability and equal access at comparable prices as directed by the Federal Energy Regulatory Commission's (FERC) Order 888, issued in April of this year. A regional power exchange, which has not existed within the ECAR region, is being discussed by the Midwest ISO participants. AEP is also evaluating alternatives in the gas markets to broaden its product range. Although the company faces restrictions as a holding company registered under PUHCA, strategic alliances are possible until PUHCA is repealed.

Subsequent to its October 1995 announcement, AEP changed the names under which its utilities provided power to the service mark "American Electric Power: America's Energy Partner". Creating brand awareness for a commodity-like product such as energy is viewed by many market strategists as a means to enhance value, to maintain customer loyalty, and to inspire confidence in reliability, an issue taken for granted in the past, but receiving increasing scrutiny as the number and type of market participants dramatically changes. The brand name will also serve the efforts of AEP's two power marketing subsidiaries, one directed at wholesale markets and the other at retail markets, both of which have FERC approval to sell power at market-based rates and thereby allow AEP to retain profits from these sales. The power marketing subsidiaries target customers beyond the reach of the traditional FERC-regulated wholesale markets within AEP's franchised service territory and and beyond neighboring utilities. AEP will continue to serve those traditional markets utilizing its rate-based generating capacity and purchased power, with profits returned to ratepayers, until full retail choice is a reality.

The SEC has approved the financing of several broad types of non-regulated investments. AEP can invest up to 50% of retained earnings (approximately $700 million) in exempt wholesale generators and foreign utility companies. The company is focusing on China, Australia, Mexico, and India. AEP can also invest $100 million in its power brokering and marketing subsidiaries. AEP filed an application in September to issue up to $150 million in short-term debt to finance investments in QFs, cooling or heating companies, and other domestic energy-related businesses. Moody's has observed that AEP pursues a very deliberative approach in its non-regulated investments. We therefore expect the company to [illegible] these approvals gradually.

Regulation and Rates

AEP — AEP owns and operates one of the most extensive transmission systems in the U.S. and as such has investment in transmission capacity as a percentage of utility plant among the highest in the U.S. FERC's Order 888, issued in April 1996, requires transmission owners subject to FERC regulation to open their transmission systems to all users at prices the utility charges itself. The intent of the order is to facilitate wholesale competition for electric energy. The utility's own retail load retains priority of usage. The order also required utilities and power pools to seek FERC approval of the comparable pricing tariffs. AEP's tariff filings have been largely approved, with some non-pricing terms still under FERC consideration. The order has little effect on AEP's transmission revenues as tariffs are cost-based, but it does expose AEP's utilities to competition for their non-affiliate wholesale customers as contracts expire.

As a registered holding company, AEP is subject to the requirements and limitations of PUHCA. While PUHCA has created an uneven "playing field" between registered and exempt holding companies, it has also served to restrict the amounts of non-regulated investment by registered holding companies. However, in AEP's case Moody's does not expect the eventual repeal of PUHCA to greatly alter the risk profile of AEP's investment activities because of the company's conservative investment strategies.

AP — AP serves customers in both the Virginia and West Virginia jurisdictions. The Virginia State Corporation Commission issued a final order on May 24, 1996, denying a requested $15.7 million rate increase. AP had filed for the increase in October of 1994, and the SCC had granted the company authority to collect the increase subject to refund since November 1994. The final order therefore requires a $26.8 million refund, which AP has provided for and completed by September 1996. The order also affected AP's margins near-term by requiring it to amortize nearly $24 million of storm damages over five years instead of three and to use a five-year rolling average member load ratio instead of a pro forma calculation. AP pays for the costs of power purchased from the AEP system pool based on its share of system load compared to its generating capacity dedicated to serving the system pool. As the amount of power AP purchased from the pool has increased, its costs have also increased. The order's method for calculating costs will cause costs to grow faster than revenues.

AP filed for a net $6.9 million rate increase, comprised of a $34 million base rate hike, a 12.75% ROE, and a $27 million fuel clause reduction, in its West Virginia jurisdiction in June 1996. AP has negotiated a settlement agreement among all parties resulting in a $5 million base rate reduction and a $27 million fuel reduction. A final order on the settlement agreement is expected shortly.

Virginia is conducting proceedings to investigate the need for restructuring the electric energy industry. West Virginia, where rates are already about 25% below the national average, has so far pursued no initiatives to introduce competition.

CSP — The most recent rate order for CSP was the January 1994 order resolving the conversion of the Zimmer plant from nuclear to coal. CSP was granted a $57 million increase with a 12.46% ROE. Of the 7.11% increase, 3.39% represented a temporary surcharge until mid-1997. The order also directed CSP to write off an additional $144.5 million after-tax in disallowed costs.

The Ohio commission has conducted roundtable meetings to investigate the effect of greater competition on the state since late 1994. In response to initiatives arising out of the roundtables, CSP has introduced new regulated rate designs in the form of interruptible buy-through contracts and real-time pri[illegible] industrial customers.

[illegible] resentat[illegible]ve Ron Amst[illegible] reintroduced a bill proposing retail wheeling in Ohio by January 1, 199[illegible]. [illegible] action was taken on the bill in this past legislative session. Moody's believes that imposition of [illegible] wheeling within the state is likely to be delayed until the legislature addresses the thorny issue of [illegible] evenues. Utilities have been major tax collectors through the state gross receipts tax and local property taxes, particularly in counties where high-cost nuclear plants are sited. These tax issues are not likely to be addressed until after 1998 elections.

I&M — I&M serves customers in two state jurisdictions: Indiana and Michigan. A November 1993 Indiana commission decision granted the utility a $35 million rate increase, with a 12.0% ROE and increased nuclear decommissioning cost recovery. The Michigan commission ordered a $10.4 million increase with a 13.0% ROE in February 1991.

Indiana has taken no initiatives to promote competition due to the competitive rates already prevalent in the state. Michigan's commission approved a small, five-year retail wheeling pilot in June 1995 involving the two largest utilities in the state, Consumers Power and Detroit Edison. The governor has endorsed a Michigan Jobs Commission proposal to permit commercial and industrial customers to choose energy suppliers by 1997, to establish a wholesale power pool by 1998, and to eliminate franchise territories by 2001.

KP — KP's last rate action was an April 1991 $11.5 million rate reduction. The Kentucky commission is not interested in greater competition within the state out of concern that rates may rise in response. The state's utilities provide electric energy at very competitive prices as their generating plants are typically sited by the coal mines, avoiding transportation costs. If competition were brought to the state, the commission is concerned that owners of power generated within the state might seek to sell that power in higher cost areas outside the state.

OP — A March 1995 Ohio commission order approved a settlement providing a $66 million, 5.8% rate hike to recover costs associated with construction of the Gavin plant scrubbers. The scrubbers are the primary component of Clean Air Act compliance across the AEP system. The compliance plan was approved by the Ohio commission. The settlement may also allow OP to recover costs associated with closing its affiliated coal mines as part of the CAA compliance plan if actual fuel costs are lower than fixed amounts stipulated in the settlement agreement. The shutdown costs could be substantial.

[See the discussion under "CSP" above regarding commission and legislative competitive initiatives within Ohio.]

Risks/Weaknesses

- The company's leverage is higher than the industry average, although this is offset by the good-to-excellent competitive positions of its member utilities.
- Because of the lack of strong regulatory support in Virginia and West Virginia as well as the absence of rate cases in other jurisdictions, the utilities must rely upon cost cutting to improve financial ratios as business risks increase.
- Only average economic growth is expected across the system.

Opportunities/Strengths

- Low-cost, coal-fired generating capacity provides a competitive advantage.
- Completed construction cycles allow lower capital expenditures and reduced regulatory risk.
- Geographic reach and a balance between competitive initiatives and a conservative investment strategy position AEP to benefit from coming deregulation.

Financial Analysis

CONSOLIDATED — Consolidated cash flow coverage measures have improved over recent years while debt-to-total-capital ratios have remained fairly constant at 52%. Pre-tax interest coverage rose from 2.32 times in 1992 to 3.11 times in 1995. Declining fuel costs have offset rising non-fuel expenses, causing total operating expenses to remain generally flat, at 83% of revenues. Reinvestment of internally-generated cash will be supported by management's pursuit of a long-term payout ratio goal of 75% compared to the actual dividend payout of 84% in 1995.

AEP pursues a systemwide environmental compliance program. Requirements of Phases I and II of the Clean Air Act have been largely met through construction of the Gavin scrubbers at Ohio Power and through fuel switching. Environmental costs for the system over the next five years are modest, totaling an estimated $144 million. 90% of this amount is targeted at modifying boilers to reduce nitrogen oxide emissions.

AP — Limited regulatory support, the largest share of construction expenditures in the AEP system, and dividends in excess of earnings have pressured leverage and coverage measures, resulting in a rating downgrade in 1996. The company expects construction to average $200 million per year over the next five years, three-quarters of which should be met through internal cash. AEP plans to provide equity contributions to allow a moderate decline in leverage and improvement in coverage over the next five years. Interest coverage in 1995 was 2.63 times, a modest improvement from 1994, but still under levels of the early 1990's. Long-term debt represents 47% of total capital. AP redeemed $25 million of preferred stock in 1996 using proceeds from issuance of junior subordinated debentures and intends to redeem an additional $50 million in early 1997. The debentures are debt, but provide some additional financial flexibility in allowing AP to defer interest payments for up to five years. Total debt at the end of 1995 including short-term debt and the junior subordinated debt was 55% of total capital.

Actual construction expenditures may vary substantially from prior forecasts. The company has attempted to construct a high-voltage transmission line across western Virginia and southern West Virginia to serve growing retail load. The Virginia commission supports the construction. The U.S. Forest Service has opposed the construction based on its possible environmental impact. AP is negotiating with the appropriate parties to balance environmental concerns with needed transmission capacity. A swift resolution may not be forthcoming. Technological advances in transmission capacity may at the same time reduce requirements and therefore estimated construction expenditures.

CSP — CSP's internal cash flow is expected to remain strong and more than ample to meet modest construction expenditures averaging $98 million per year over the next five years. Both coverage and leverage measures should continue to improve. Pre-tax interest coverage was 3.5 times in 1995 compared to 2.0 times in 1992. CSP redeemed $72 million of preferred stock through issuance of junior subordinated debentures in 1995. Long-term debt excluding the debentures was 51% of total capital at year end. Total debt including short-term debt and the junior subordinated debentures was 57%. Dividend payout in 1995 was 73%.

I&M — Strong cash flow will continue to allow the company to meet its capital expenditures, estimated at $104 million per year over the next five years, out of internally-generated funds. Pre-tax interest coverage of 3.8 times in 1994, compared to 2.8 times in 1992, is expected to continue to improve. I&M's balance shee[illegible]vhat leveraged by lease payments associated with its share of the Rockport plant. Unadjus[illegible] year [illegible]995 w[illegible]9% of total capital. I&M added a slim amount of junior subordinate[illegible]es in[illegible] refin[illegible]g preferred stock and lo[illegible]erm debt.

The most recent estimates in 1[illegible]f decommissioning costs for the Cook nuclea[illegible]its ranged from $634 million to $988 million[illegible]ese costs are being recovered in rates up to at least the lower end of the range.

KP — KP added $40 million of junior subordinated debentures to its balance sheet in 1995, refinancing short-term debt. Total debt, at 59% of total capital in 1995, represents leverage higher than is typical for its rating category. KP's very competitive costs and rates plus its size within the AEP system offset the greater leverage. Both coverage and leverage measures are expected to remain stable over the intermediate term. Interest coverage in 1995 was 2.2 times. The company expects to meet only one-third of construction expenditures, expected to average $62 million over the next five years, through internal cash. Parent equity contributions are intended to support the construction program.

OP — The Gavin scrubber rate settlement in 1995 supports continued strong cash flow. The scrubber lease adds leverage to the balance sheet, however total adjusted debt remains in the mid-50% range and is expected to decline over the intermediate term. Unadjusted pre-tax interest coverage was a strong 4.0 times in 1995, substantially improved from 3.0 times in 1992, and is expected to continue to strengthen.

OP owns three high-sulfur coal mines, two of which are likely to be closed to comply with Phase II of the CAA. OP may not be able to recover all of the estimated $195 million after-tax, non-Ohio-jurisdictional shutdown costs. However, the current rating outlook assumes OP has the ability to substantially recover these costs through the Gavin settlement agreement terms and to manage the financial impact of any unrecovered amounts.

(Continued from page 2)

Coupon	Type of Debt	Maturity	Moody's Rating
Columbus Southern Power Company			
7.600%	Sr. Sec. Medium-Term Notes	2024	A3
7.450%	Sr. Sec. Medium-Term Notes	2024	A3
6.850%	Medium Term Notes	2005	Baa1
6.750%	Sr. Sec. Medium-Term Notes	2004	A3
6.550%	Sr. Sec. Medium-Term Notes	2004	A3
	Counterparty Rating		Baa1
7.000%	First Mortgage Bonds	1998	A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	MTN Program		Baa1
7.875%	Cum. Pfd. Stk.		"baa1"
7%	Cum. Pfd. Shs.		"baa1"
	Commercial Paper		P-2
Indiana Michigan Power Company			
6.400%	Sr. Sec. Medium-Term Notes	2000	Baa1
	Counterparty Rating		Baa2
7.000%	First Mortgage Bonds	1998	Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
7.250%	S.F. Debenture	1998	Baa2
6.3%	Cum. S.F. Pfd. Stk.	2009	"baa2"
6.25%	Cum. Pfd. Stk.	2009	"baa2"
5.9%	Cum. S.F. Pfd. Stk.	2009	"baa2"
4.125%	Cum. Pfd. Stk.		"baa2"
4.12%	Cum. Pfd. Stk.		"baa2"
7.08%	Cum. Pfd. Stk.		"baa2"
6.875%	Cum. Pfd. Stk.		"baa2"
	Commercial Paper		P-2
	415 Shelf Registration		(P)Baa1
Kentucky Power Company			
6.910%	Medium Term Notes	2007	Baa2
	Counterparty Rating		Baa2
7.875%	First Mortgage Bonds	2002	Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	Secured MTN Program		Baa1
	MTN Program		Baa1
	MTN Program		Baa2
	Commercial Paper		P-2
	415 Shelf Registration		(P)Baa2

Kentucky Power Co.

Ashland, Kentucky, USA

Ratings

Category	Moody's Rating
Senior Secured MTN	Baa1
Counterparty Rating	Baa2
Junior Subordinated	Baa3
Senior Secured Shelf	(P)Baa1
Senior Unsecured Shelf	(P)Baa2
Commercial Paper	P-2

Contacts

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American Electric Power Company, Inc.

Commercial Paper	P-2

Rating History

Operating Statistics

Kentucky Power Company (Statistics in bold type)
Peer Group Median (Statistics in light type)

	[1]1997	1996		1995		1994		1993		[2]5-Yr.Avg.	
Revenue (US$ bil.)	**0.3**	1.2	**0.3**	1.2	**0.3**	1.1	**0.3**	1.1	**0.3**	[3]2.0	**[3]1.1**
Assets (US$ bil.)	**0.9**	3.4	**0.8**	3.2	**0.8**	3.1	**0.7**	3.2	**0.7**	[3]3.8	**[3]6.4**
Com. Equity (US$ bil.)	**0.2**	1.0	**0.2**	1.0	**0.2**	1.0	**0.2**	0.9	**0.2**	[3]2.4	**[3]4.6**
Op. Margin (%)	**16.0**	22.7	**14.6**	25.0	**16.7**	21.8	**16.2**	21.3	**14.0**	22.6	**15.6**
ROA (avg.)(%)	**2.5**	3.7	**2.1**	3.9	**3.4**	3.6	**3.7**	4.1	**2.8**	3.8	**3.3**
ROE (avg.)(%)	**8.5**	12.9	**7.3**	12.9	**11.7**	12.5	**12.5**	12.0	**9.2**	12.4	**10.8**
Div. Payout (%)	**129.8**	76.9	**143.0**	80.9	**91.2**	81.5	**84.7**	79.9	**125.8**	80.9	**105.5**
Pretax Int. Cov. (X)	**2.2**	3.5	**2.0**	3.5	**2.2**	3.3	**2.3**	3.2	**2.0**	3.3	**2.2**
Fxd. Chg. Cov. (X)	**2.2**	3.0	**2.0**	3.0	**2.3**	2.5	**2.4**	2.5	**2.0**	2.7	**2.2**
RCF % TD	**6.7**	15.1	**5.3**	15.3	**6.6**	12.7	**5.7**	11.5	**5.2**	13.3	**6.2**
RCF % Gross CAPEX	**29.5**	120.2	**24.2**	131.9	**54.0**	85.0	**34.6**	87.4	**44.5**	103.0	**45.3**
Total Cap. (US$ bil.)	**0.6**	2.2	**0.6**	2.2	**0.5**	2.2	**0.5**	2.2	**0.5**	[3]0.0	**[3]4.7**
TD % Cap.	**59.3**	50.3	**58.6**	51.8	**59.2**	52.6	**60.6**	52.1	**60.6**	51.9	**59.3**
Pfd. Stk. % Cap.	**0.0**	5.7	**0.0**	5.8	**0.0**	7.6	**0.0**	6.7	**0.0**	6.4	**0.0**
Common % Cap.	**40.7**	43.9	**41.4**	43.1	**40.8**	41.2	**39.4**	41.0	**39.4**	41.9	**40.7**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	**106.4**	**58.4**	**92.3**	**57.1**
Kwh(mil.)	**2191**	**1151**	**3076**	**3680**
¢/Kwh	**4.9**	**5.1**	**3.0**	**1.6**
Industry Avg. (¢/Kwh)	**7.9**	**6.9**	**4.5**	**2.7**
Competitive Position	**Break-even Price($)**	**Regional Avg.($)**	**Stranded Cost($mil.)**	**Stranded Cost % Eq.**
	5.41	**51.93**	**0**	**0**

[1] For the 12 months ended September 30; Balance sheet items are as of September 30. [2] Five year average 1996-1992. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

Kentucky Power Company's (KP) Baa1 senior secured rating reflects the benefits of membership in the American Electric Power (AEP) system, the company's very competitive generating costs, its low Clean Air Act compliance costs, and the slow pace of restructuring within the state of Kentucky. However, the rating also reflects the company's highly leveraged balance sheet, large percentages of industrial and wholesale customers, and generating asset concentration.

The 1,060 mw, coal-fired Big Sandy plant represents 73% of KP's capacity. This owned capacity is supplemented by a long-term contract to purchase 390 mw from the AEP system's Rockport plant. These purchases represent a substantial off-balance-sheet obligation, which when fully reflected on the balance sheet, exacerbates an already weak capital structure.

The company expects that over the next five years internal cash flow will meet only 45% of capital expenditures, most of which are needed to improve transmission and distribution. The company will rely on parent support and on the capital markets to meet the balance of its spending needs.

Rating Outlook

We view KP's credit ratings as stable. We believe that the intercompany nature of KP's power purchases and AEP's support of this small subsidiary substantially offset the risks of a financial profile weaker than the industry norm.

Moody's Investors Service
Global Credit Research

American Electric Power Company, Inc.

December 1997

Ratings

Category	Moody's Ratings
Commercial Paper	P-2
Appalachian Power Company	A3
Columbus Southern Power Company	A3
Indiana Michigan Power Company	Baa1
Kentucky Power Company	Baa1
Ohio Power Company	A3

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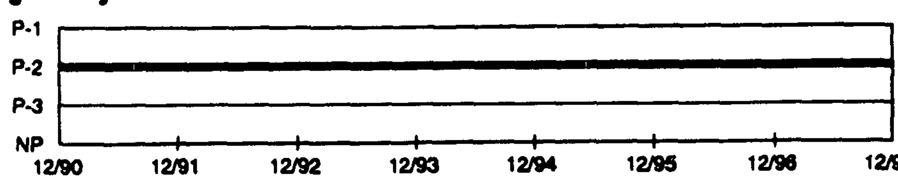
Rating History



Operating Statistics

American Electric Power Company, Inc.

	[1]1997	1996	1995	1994	1993	[2]5-Yr.Avg.
Revenue (US$ bil.)	5.9	5.8	5.7	5.5	5.3	[3]3.0
Assets (US$ bil.)	16.3	15.9	15.9	15.7	15.3	[3]2.8
Com. Equity (US$ bil.)	4.6	4.5	4.3	4.2	4.2	[3]1.5
Op. Margin (%)	22.9	23.1	22.1	21.2	21.9	21.6
ROA (avg.)(%)	3.2	3.7	3.4	3.2	2.4	3.2
ROE (avg.)(%)	11.3	13.2	12.4	11.9	8.4	11.4
Div. Payout (%)	93.6	76.5	84.1	88.6	125.2	93.8
Pretax Int. Cov. (X)	3.5	3.5	3.1	2.9	2.8	2.9
Fxd. Chg. Cov. (X)	3.2	3.0	2.2	2.1	2.0	2.3
RCF % TD	9.8	13.1	13.7	8.0	8.7	10.6
RCF % Gross CAPEX	81.6	120.4	124.6	66.9	78.8	95.0
Total Cap. (US$ bil.)	10.8	10.4	10.5	10.4	10.3	[3]0.2
TD % Cap.	55.2	50.7	52.5	51.6	52.0	51.9
Pfd. Stk. % Cap.	1.6	5.8	6.3	7.9	7.5	6.9
Common % Cap.	43.2	43.5	41.2	40.5	40.5	41.2

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	1,958.6	1,284.7	1,618.8	792.6
Kwh(mil.)	30853	22558	45395	32503
¢/Kwh	6.3	5.7	3.6	2.4

[1] For the 12 months ended September 30; Balance sheet items are as of September 30. [2] Five year average 1996-1992. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

The A3 and Baa1 ratings for American Electric Power's (AEP) utilities are based on the system's strong competitive position. The ratings also reflect generally modest service territory growth and leverage slightly above industry norms as the result of only moderate regulatory support in many jurisdictions.

AEP's sales are concentrated in the industrial sector, which contributed 45% of 1996 retail sales. As the electric utility industry evolves towards open price competition, the threat of customer loss is higher among this class than any other. However, we believe that AEP's average 1996 industrial rate of 3.57 cents per kwh, substantially below the national average of 4.64 cents, will allow the company to compete aggressively to not only maintain, but also to improve market share.

The system's 87% coal-fired generating capacity has required substantial Clean Air Act (CAA) compliance costs, which are being recovered through retail rates and system power pool sales. The CAA compliance costs still to be incurred over the next five years, primarily for nitrogen oxide modifications on boilers, will be modest. Other capital expenditures are also manageable as the AEP power pool system will allow members to defer construction of additional generating capacity beyond 2000.

AEP's global expansion of non-... energy-related ventures took a leap forward with its 1997 acquisition through a 50/50 joint venture with Public Service of Colorado of the UK's Yorkshire Electricity plc for $2.88 billion.

Rating Outlook

The rating outlooks for AEP's subsidiaries are stable. We expect the announced merger with Central and SouthWest to have no near-term financial impact.

Coupon	Type of Debt	Maturity	Moody's Rating
American Electric Power Company, Inc.			
	Commercial Paper		P-2
American Elect Power Service Co.			
Appalachian Power Company			
8.000%	Sr. Sec. Medium-Term Notes	2025	A3
8.000%	Sr. Sec. Medium-Term Notes	2005	A3
7.850%	Sr. Sec. Medium-Term Notes	2004	A3
6.710%	Sr. Sec. Medium-Term Notes	2000	A3
6.350%	Sr. Sec. Medium-Term Notes	2000	A3
	Counterparty Rating		Baa1
9.875%	First Mortgage Bonds	2020	A3
6.800%	First Mortgage Bonds	2006	A3
7.500%	First Mortgage Bonds	2002	A3
7.625%	First Mortgage Bonds	2002	A3
6.375%	First Mortgage Bonds	2001	A3
7.500%	First Mortgage Bonds	1998	A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
	Secured MTN Program		A3
5.9%	Cum. Pfd. Stk.	2008	"baa1"
6.85%	Cum. Pfd. Stk.	2004	"baa1"
4.5%	Cum. Pfd. Stk.		"baa1"
4.5%	Cum. Pfd. Stk.		"baa1"
7.4%	Cum. Pfd. Stk.		"baa1"
5.92 %	Cum. Pfd. Stk.		"baa1"
	Commercial Paper		P-2
	415 Shelf Registration		(P)A3

(Continued on page 20)

Author	Senior Associate
Emily J. Eisenlohr	*Brad Swinsburg*

Company Fundamentals

BUSINESS FUNDAMENTALS AND COMPETITIVE POSITION

American Electric Power Company (AEP) is one of 13 registered utility holding companies regulated by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. AEP is a system of five large electric utilities (the "member utilities"); Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company; two small distribution utilities; one wholesale electric generating company, AEP Generating Company; and a non-regulated development and investment subsidiary, AEP Resources. Although the utilities retain their separate legal existence and indentures, they have been serving customers under the brand name "American Electric Power", since 1996. Table 1 details the size and market characteristics of the five member utilities.

Table 1: 1998 Utility Overview

	AP	CSP	I&M	KP	OP
Operating Revenues ($000,000)	1,625	1,106	1,328	323	1,912
Sales as % of Retail Sales:					
Residential	39	37	31	34	21
Commercial	21	39	26	18	15
Industrial	38	20	43	48	64
Wholesale as % of Total Sales	38	24	53	36	40
Service Territory	VA, WV	OH	IN, MI	KY, TN	OH
Retail Customers	867,000	609,000	542,000	167,000	673,000
Competitive Position	Above Aver	Average	Average	Above Aver	Above Aver

THE SYSTEM

The five member utilities benefit from their membership in the AEP system pool through cost sharing and the deferral of construction of new capacity. The parent pursues selective investment strategies and can also manage the capital structure of a subsidiary to a modest degree through capital contributions and upstreamed dividends. The financial and operating flexibility advantages of the AEP system currently have a small positive impact on ratings relative to what the ratings of each individual utility on a stand-alone basis might be.

AEP operates the member utilities' 23,759 megawatts of generating capacity as a power pool under an economic dispatch system, 85.0% coal-fueled, 11.6% nuclear-fueled, and less than 1% hydro-powered. A member that sells more power to its retail customers than it has capacity to produce becomes a net purchaser from the pool. Net purchasers (Appalachian Power and Columbus Southern) compensate the sellers (Ohio Power, Indiana Michigan, and, to a small extent, Kentucky Power) for the seller's embedded costs, including capacity, operations, maintenance, and fuel. Table 2 illustrates the revenue and cost sharing resulting from the five members' participation in interconnection, transmission, and system wholesale power sales agreements. The cost sharing agreement, approved by the SEC as AEP is a registered holding company, may be revised in the future to accommodate the changing industry dynamics.

Table 2: 1998 SHARED COSTS AND CREDITS ($000)

Subsidiary	Generation	System Wholesale Power Sales	Power Pool Transmission	Transmission for Non-Affiliated Companies
AP	(258,000)	36,800	(6,500)	13,800
CSP	(145,000)	18,100	(30,600)	8,000
I&M	121,000	43,000	46,300	7,700
KP	2,000	7,600	3,300	2,800
OP	280,000	30,200	(12,500)	17,800

Members of the power pool arrangement earn no return on sales to the pool, but membership allows deferral of construction of additional generating capacity beyond what otherwise might have been needed.

Under current projections, AEP will not need new capacity until after 2001. Due to weather patterns the summer peak reserve margin increased only slightly from 15.8% in 1995 to 16.3% in 1996. The company estimates a weather-normalized reserve margin of 15% on the 2000-2001 horizon due to estimated peak demand growth of only 0.7% per year over the next five years compared to 2.9% over the past five years. The company estimates that retail sales will grow 1.0% over the next five years, slower than the 2.9% pace of the past five years. As competition increases, many industry participants view as appropriate a lower standard than the 15-20% reserve margin range commonly accepted as prudent in ratemaking proceedings across the nation. That changing standard is another reason AEP is able to postpone construction of additional capacity.

Moody's estimates that the AEP faces only minimal potential stranded costs from its investment in generation, which are detailed below. Moody's views this risk as manageable and also mitigated by the operating cost advantages provided by the system's generating plant. Individual states that are pursuing legislation mandating customer choice of energy supplier are each defining stranded costs differently to reflect the structure of that state's energy sector. Therefore, some states may mandate stranded cost recovery for a type of cost that is not included in Moody's model, for example, labor costs related to the transition. Moody's stranded cost estimates were developed for the purpose of comparing competitive positions rather than as a prediction of what actual stranded costs might be.

Wholesale sales to non-affiliated utilities rose significantly from 18% of consolidated sales in 1995 to nearly 25% in 1996. AEP, interconnected with 29 neighboring utilities at 143 sites, is pursuing new markets outside its service territory. Contracts presently total 1320 megawatts. We expect that the system's wholesale power sales will continue to grow to the extent that it can source cost-effective wholesale power and utilize its extensive transmission network.

We believe that AEP's generation system will be among the most competitive in the deregulating industry. Declining fuel costs have offset slightly higher non-fuel operating and maintenance costs over the past few years, resulting in total production costs in the 2.0-2.1 cents per kilowatthour range. The production cost advantage allows the company to offer competitive rates. For 1996, the company's rates in the fiercely competitive industrial sector averaged 3.57 cents per kilowatthour compared to the national average of 4.64 cents. The utilities individually have competitive positions of average to above-average, as discussed below and as demonstrated in Table 3.

The Subsidiaries

APPALACHIAN POWER COMPANY (AP) — AP contributes 28% of AEP's operating revenues. AP uses its 5,853 megawatts (mw) of mostly coal-fired, highly competitive generating capacity and purchased power to serve customers in Virginia and West Virginia. The company estimates retail sales growth of 2.2% over the next five years, a somewhat slower pace than the 2.9% growth rate of the past five years. The economy in the Virginia portion of the service area is expected to be stronger than that of the West Virginia service area. Industrial customers, which represent 38% of the company's retail sales, include primary metals, chemicals, textiles, paper, and coal mining companies. AP's 1996 industrial rate of 3.64 cents was well below the national average of 4.64 cents.

AP's wholesale sales, which represent 38% of total sales, are to other non-affiliated utilities, and to an affiliated non-pool-member, Kingsport Power. Reflecting the impact of the Federal Energy Regulatory Commission's open access Order 888, customers have given notice of termination for nearly two-thirds of total demand on contracts effective in 1998-1999. We anticipate that AP will be able to retain some of this load and that the loss of some of these contracts will have little impact on the company's margins as it is a net purchaser of power from the AEP system.

COLUMBUS SOUTHERN POWER COMPANY (CSP) — CSP contributes 19% of AEP's total operating revenues. CSP's sales to the robust Columbus, Ohio commercial sector account for 39% of CSP's retail sales. Industrial sales account for only 20% of retail sales and are spread across a number of industries. The company's industrial rates are about equal to the national average. The company estimates that retail sales will grow 2.7% per year over the next five years, slightly above the national average but at a slower rate than the 3.2% over the past five years. Regional unemployment is expected to remain below national levels.

CSP's 2,595-mw generating capacity is completely coal-fired. The nuclear-to-coal conversion of the Zimmer plant, which is jointly owned with two unaffiliated utilities, was completed in 1991. While the Zimmer plant is among the most efficient in its region, it is also the source of most of CSP's stranded cost exposure due to its fixed costs. Moody's estimates of stranded cost exposure declined from 70% of equity in 1995 to 49% of equity in 1996 due to an increase in the equity base and a decrease in the absolute level of stranded costs. Zimmer's costs are reflected in current rates. Moody's expects these stranded costs to be manageable given their decreasing magnitude and the other competitive advantages of the AEP system.

INDIANA MICHIGAN POWER COMPANY (I&M) — I&M contributes 23% of the AEP system's revenues. The state of Indiana accounts for over 80% of the utility's retail sales, with Michigan making up the balance. Industrial sales account for 43% of total retail sales, with concentrations in primary metals, electrical machinery, transportation equipment, chemicals, and fabricated metals. Reflecting a healthy local economy, the company expects retail sales growth to slow to 2.1% per year over the next five years, after growing at an annual pace of 4.3% over the previous five years.

I&M's competitive position is average due to its generating cost and rate structures. Its industrial rates equal the regional average. The two Cook nuclear units represent 47% of I&M's 4,434 megawatts of generating capacity, and nearly all of the balance is coal-fired. Based upon 1996 data, Moody's estimates I&M's stranded costs at a manageable 40% of equity, substantially improved from the prior year due to lower operating costs at the Cook units. Although performance at the two nuclear units has improved in recent years, both units were shut down in early September of 1997. The shutdowns were due to concerns about plant systems functionality in the event of an accident, not because of any equipment malfunctions. The AEP system has sufficient reserve to replace the lost power during the shutdown, but will miss the opportunity to sell excess power in the wholesale market. I&M has also announced plans to replace the four steam generators in Cook Unit 1, with an expected capital cost that could exceed $175 million. The replacement will take place during a regularly scheduled refueling outage in the spring of 2000 and the unit is expected to be out of service for about 100 days. The company expects to meet the costs primarily through internal cash.

Off-system sales, which comprised 53% of total sales in 1996 and which include wholesale sales made to the pool, are important to I&M's financial health. I&M and AEP Generating Company each have a 50% interest in both Rockport units, whose total capacity is 2,600 mw. (Rockport 2, which went into commercial operation in 1989, is financed through an operating lease.) I&M purchased an additional 455 mw of Rockport capacity from AEG. I&M has sold 250 mw of its total Rockport capacity to an unaffiliated utility under a long-term contract expiring in 1999. I&M uses the remaining 1,505 mw to meet its retail and power pool demand. I&M's highly volatile off-system sales account for a shrinking percentage of total revenues, offset by the increase in more profitable retail sales.

KENTUCKY POWER COMPANY (KP) — KP is the smallest of the member utilities, contributing only 6% of revenues. It has one generating source, the 1,060-mw coal-fired Big Sandy plant. Although it is a net seller to the power pool, purchased power costs totaled 39% of the utility's operating and maintenance costs in 1996, including purchases from AEP Generating. Still, the utility's competitive position is above both regional and national averages as a result of its low generating cost structure and reasonable rates. As a result, we expect the company to retain its industrial customer base, which is concentrated in petroleum, primary metals, and chemicals, and which accounts for 48% of total retail sales. The company anticipates retail sales growth of 2.0% per year over the next five years, down slightly from the 3.0% per year of the past five years.

OHIO POWER COMPANY (OP) — OP accounts for nearly 33% of AEP's revenues, the highest share among the system's member utilities. The utility is also the largest net seller of power to the system power pool. Its 8,464-mw generation capacity serves not only its own retail customers in Ohio, but also wholesale customers, which, including the AEP power pool, comprise 40% of sales. Retail sales, which have grown an average of 2.3% per year over the last five years, are expected to have a -2.1% growth rate over the next five years reflecting the loss of the Ormet Corporation contract in 2000. Industrial customers, which contribute 64% of retail sales, are heavily concentrated in primary metals, but also include such industries as petroleum, rubber, plastics, stone, clay, glass, chemicals, transportation equipment, and electrical machinery. Although competition is fierce in the industrial sector, OP's low industrial rates, which average 3.18 cents per kilowatthour compared to the national average of 4.64 cents, provide a strong competitive edge.

Expiration of two major industrial contracts, Ormet Corporation and Ravenswood Aluminum, which together account for 890 mw of demand, is cause for only modest concern despite OP's low growth rate and high reserve margins. The Ormet contract was extended through 1999, at which time an alternate supplier is replacing Ohio Power. The contract with Ravenswood was extended through 2003. Both contracts currently entail low margins. Moody's expects retail sales growth within the AEP system, growing system wholesale contracts, and retention of associated transmission revenues to offset potential loss of this demand.

Table 3: 1996 RATE COMPARISONS

Company	Industrial	Commercial	Residential
AP	3.64	5.07	5.58
CSP	4.81	6.46	7.83
I&M	4.29	5.86	6.69
KP	3.00	5.08	4.86
OP	3.18	5.54	6.64
AEP System	3.57	5.69	6.35
ECAR Average	4.52	7.10	7.73
National Average	4.64	7.63	8.64

Source: RRA and Moody's

AEP GENERATING COMPANY — AEP Generating Company generates and sells power at wholesale from Rockport Units 1 and 2, in which AEP Generating and I&M each have a 50% interest. Unit 1 is owned, and Unit 2 is leased. KP purchases 30%, or 390 mw, of AEP Generating's share of the power generated by each Rockport unit under a contract expiring at the end of 1999. An unaffiliated utility purchases 70%, or 455 mw, of AEP Generating's share of power available from Rockport Unit 1 through the end of 1999. The remaining portion of AEP Generating's share of Unit 2 is sold to I&M. AEP Corporation (the parent) provides financial support to AEP Generating under a capital funds agreement, ensuring that it will be able to meet any financial obligations.

OTHER SUBSIDIARIES — AEP established AEP Resources to invest in non-regulated power projects around the globe and in foreign utility companies. Resources' is involved in a joint venture to build two 125 mw coal-fired electric generating units in China. The total cost of the project is projected to be $172 million, of which AEP Resources' share amounts to approximately $120 million. In April of 1997, AEP Resources' acquired, along with Public Service Company of Colorado, Yorkshire Electricity Group plc at a total consideration of $4.2 billion. AEP and Conoco, the energy subsidiary of DuPont, have agreed to form two jointly held venture companies to provide energy management and capital to industrial and large commercial facilities and provide future capital for energy projects. AEP Conoco Energy Capital and AEP Conoco Energy Management Services will initially acquire and manage industrial energy assets for 16 DuPont facilities having an estimated value of $500 million and for an additional 17 facilities within the next year, also having an estimated value of $500 million.

Management Strategy

AEP is progressing towards its goal of being an energy services provider, not just an electric utility. Its corporate strategic priorities, aligned with those of CSW, include:

- Growing the core business and the associated base of existing customers, remaining in all three functional competencies of generation, transmission, and distribution.
- Establishing a national energy trading presence.
- Building a portfolio of global investment and development projects (example Yorkshire acquisition in the UK).
- Expanding product and service offerings across the energy sector and in telecommunications to enhance customer loyalty (example Conoco alliance).
- Acquiring incremental assets such as transmission or generation to support the trading business or other growth strategies.

Moody's regards the pace at which AEP is expanding into non-regulated energy investments, power marketing, and power project development as deliberative and more conservative than other holding companies of its size. Three factors restrain what might otherwise be a faster rate of investment. First, AEP faces some limitations as a holding company registered under PUHCA, particularly in the natural gas sector. Management is at the forefront of PUHCA repeal. Second, AEP's sheer size within its region is likely to attract keen scrutiny of market power issues as it pursues initiatives close to home. Finally, valuations of most investment opportunities are rich, lowering returns below AEP's disciplined hurdle rates.

AEP management has publicly supported full consumer choice of energy suppliers since the October 1995 announcement of their vision of the future. They also support recovery of stranded costs, a limited issue for AEP, but a significant one in the larger state jurisdictions within their service territory. In preparation, the company has reduced costs, enhanced its technological infrastructure and capabilities, reorganized along functional lines, and streamlined the workforce.

AEP is one of the founding members of the Midwest Independent System Operator (MISO), an organization intended to centrally manage an extended multi-state transmission grid with major goals of reliability and equal access at comparable prices as directed by the Federal Energy Regulatory Commission's (FERC) Order 888, issued in April 1996. MISO is expected to file its application for approval with the FERC by year end.

Subsequent to its October 1995 announcement, AEP changed the names under which its utilities provided power to the service mark "American Electric Power: America's Energy Partner". Creating brand awareness for a commodity-like product such as energy is viewed by many market strategists as a means to enhance value, to maintain customer loyalty, and to inspire confidence in reliability, an issue taken for granted in the past, but receiving increasing scrutiny as the number and type of market participants dramatically changes. The brand name will also serve the efforts of AEP's power marketing initiatives, at both the wholesale and retail markets. AEP has been a profitable participant in the wholesale markets, but profits have had to be returned to ratepayers as they financed AEP's generating base. Ability to expand beyond the region and to sell as a power marketer at market-based rates will allow profits to be retained by shareholders. Moody's notes, however, that power marketing entities typically experience razor-thin margins and entail much higher risk than the traditional utility.

AEP can invest up to 50% of retained earnings (approximately $800 million) in exempt wholesale generators and foreign utility companies. The company has a request to increase the limit to 100% pending before the SEC. All seven states in which their regulated utilities do business have issued letters that they are not opposed to the increase. Offices have been established in the four regions of investment interest: in Toronto and Columbus for the North American market; in London for the European markets; in Sydney, Beijing, and Singapore for the Pacific Rim region; and a location to be determined for Latin America. The company is focusing on China, Australia, India, Mexico, Brazil and European opportunities. Management intends to diversify by country and by type of project (fuel type; greenfield versus acquisition; generation, transmission, and distribution) to minimize volatility in cash flows, but at the same time not to dilute management attention by involvement in too many countries.

Regulation and Rates

AEP — AEP owns and operates one of the most extensive transmission systems in the U.S. and as such has investment in transmission capacity as a percentage of utility plant among the highest in the U.S. FERC's Order 888, issued in April 1996, requires transmission owners subject to FERC regulation to open their transmission systems to all users at prices the utility charges itself. The intent of the order is to facilitate wholesale competition for electric energy. The utility's own retail load retains priority of usage. The order also required utilities and power pools to seek FERC approval of the comparable pricing tariffs. AEP's tariff filings have been approved and remain cost-based. While Order 888 does expose AEP's utilities to competition for their non-affiliate wholesale customers as contracts expire, it has also resulted in increased utilization of the transmission system with a corresponding increase in transmission revenues.

As a registered holding company, AEP is subject to the requirements and limitations of PUHCA. While PUHCA has created an uneven "playing field" between registered and exempt holding companies, it has also served to restrict the amounts of non-regulated investment by registered holding companies. The evenutal repeal of PUHCA, in Moody's opinion, will not greatly alter the risk profile of AEP's investment activities. While the non-regulated investments grow in size and number, the company's investment strategies are still very selective and deliberative in their pace of growth.

The EPA has targeted four states in which AEP operates for Nitrogen Oxide reduction of 40% or more. Indiana, Kentucky, Ohio, and West Virginia must have pollution controls in place by 2002 and clean air benefits are to be attained by 2005. In a worst case scenario AEP management expects costs for the program to amount to $1.6 billion in capital expenditures and approximately $400 million annually in O&M expenses. AEP believes the EPA reductions are excessive. Significant political hurdles stand in the way of implementing the new standards, so 2002 may be a much too aggressive deadline. Moody's has not factored these potential new environmental compliance costs into ratings because of the uncertainties surrounding net impact and timing.

AP — AP serves customers in both the Virginia and West Virginia jurisdictions. On June 13, 1997, AP filed an application with the Virginia State Corporation Committee (Virginia SCC) for approval of an alternative regulatory plan and an increase in annual base rates of $30.5 million, effective July 13, 1997. On July 10, 1997 the Virginia SCC issued an order suspending implementation of new rates until November 11, 1997 and a public hearing has been scheduled for May of 1998 to consider AP's proposals. On December 20, 1996 AP filed an application with the Virginia SCC to increase its annual fuel factor revenues by $17 million. The Virginia SCC approved the request, effective February 1, 1997.

On December 27, 1996 the West Virginia PSC approved a settlement agreement that would reduce AP's base rates by $5 million and Expanded Net Energy Cost (ENEC) by $28 million. Under the terms of the agreement, AP's rates would not change prior to January 1, 2000 and an ENEC recovery balance would be kept. Regardless of the recovery balance as of December 31, 1999, ratepayers would not be responsible for any underrecovery and would likely benefit from any overrecovery.

AP filed applications with the Virginia SCC and PSC of West Virginia during 1997 for certificates to build a 132 mile 765-kilovolt transmission line between the two states. The need for the new line was identified in 1990, but regulatory delays have postponed the project. The most recent application, although as yet unapproved, has been revised to account for changes recommended by the U.S. Forest Service and environmental experts that would re-route the line to avoid [illegible] wildlife areas in Virginia. The project currently has an approximate cost of $263 million.

Since September 1995, Virginia has conducted proceedings to investigate the need for restructuring the electric energy industry. On November 7, 1997, the staff of the Virginia State Corporation Commission delivered its report recommending a framework for transition to a more competitive electric energy market in the state, as directed by the legislature. The staff recommended a two-phase, overlapping approach. The first phase, covering the period 1998-2001, is an experimental period in which utility rates in the state are thoroughly examined, pilot programs designed and implemented, and new mechanisms established to manage a more active market such as an independent system operator of the transmission system and a new regional power exchange. In the second phase, from 2000 to 2002, the decision whether to proceed with implementing full choice would be made using the results of the study phase and implementation begun if appropriate. AP, along with several other large utilities, filed its own transition rate case (described above) as requested by the Virginia SCC.

West Virginia, where rates are already well below the national average, has only recently initiated a general investigation into the restructuring of the electric energy industry under the direction of the Public Service Commission of West Virginia. On May 8, the commission established an investigative task force whose report was delivered to the commission on October 15, 1997, outlining areas of consensus, but making no recommendations.

[illegible] - The most recent rate order for CSP was the January 1994 order resolving the conversion of [illegible]mer plant from nuclear to coal. CSP was granted a $57 million increase with a 12.46% ROE. Of [illegible] 7.11% increase, 3.39% represented a temporary surcharge which ceased in June of 1997 and res[illegible]d in the recovery of $93.9 million. The order also directed CSP to write off an additional $14[illegible] million after-tax in 1993.

The Ohio commission has conducted roundtable meetings to investigate the effect of greater competition on the state since late 1994. In response to initiatives arising out of the roundtables, CSP has introduced new regulated rate designs in the form of interruptible buy-through contracts and real-time pricing to its industrial customers.

A joint state legislative committee, set up in early 1997, was originally scheduled to release a report in October of the current year. The report has been delayed, but may be out by year-end. The report was originally intended to provide recommendations to the legislature in their efforts to draft restructuring legislation. In February 1997, a bill was introduced in the Ohio House of Representatives that was essentially the same bill that was introduced in the previous session. The bill, H.B. 220, proposes that all customers be permitted to select their electricity suppliers effective January 1, 1998. Stranded cost recovery has become an issue of debate and progress towards deregulation is unlikely until it is resolved. Tax issues may also delay retail wheeling, within the state. Utilities have been major tax collectors through the state gross receipts tax and local property taxes, particularly in counties where high-cost nuclear plants are sited. These tax issues are not likely to be addressed until after 1998 elections. In mid-November a bill was introduced to allow securitization of government mandated electric utility costs. While it doesn't address a deadline for customer choice, it would support the transition to choice by speeding recovery of stranded costs.

I&M — I&M serves customers in two state jurisdictions: Indiana and Michigan. A November 1993 Indiana commission decision granted the utility a $35 million rate increase, with a 12.0% ROE and increased nuclear decommissioning cost recovery. The Michigan commission ordered a $10.4 million increase with a 13.0% ROE in February 1991.

Indiana has taken initiatives to promote competition despite the competitive rates already prevalent in the state. A bill designed to introduce competition into the state has been amended to have a legislative committee study electric industry competition. In June of 1997 the Michigan commission approved a state restructuring plan that opens Michigan's electric industry to competition by 2002. A group of electric utility stakeholders have proposed an alternative deregulation plan and asked state legislatures to consider the plan during the summer recess. In August 1997, a petition supported by the states Attorney General Frank Kelley was brought before the Ingham County Circuit Court to stop deregulation proceedings until the PSC has determined that it has the authority to order retail wheeling.

KP — In a May 27, 1997 order KP's request for a monthly surcharge to recover environmental compliance costs was approved by the Kentucky Public Service Commission (KPSC). The order also directed KP to refund $2.3 million in emission allowance sale proceeds to ratepayers. Management has appealed the refund order and expects to prevail. No provision for loss has been recorded.

The Kentucky commission has been reluctant to pursue electric restructuring within the state out of concern that rates may rise in response. The state's utilities provide electric energy at very competitive prices as their generating plants are typically sited by the coal mines, avoiding transportation costs. If competition were brought to the state, the commission is concerned that owners of power generated within the state might seek to sell that power in higher cost areas outside the state. However, in December, 1996 the Public Service Commission initiated a series of informal, one-to-one, fact finding conferences with utilities and consumer groups to discuss the issues and concerns surrounding electric restructuring.

OP — A March 1995 Ohio commission order approved a settlement providing a $66 million, 5.8% rate hike to recover costs associated with construction of the Gavin plant scrubbers. The scrubbers are the primary component of Clean Air Act compliance across the AEP system. The compliance plan was approved by the Ohio commission. The settlement may also allow OP to recover costs associated with closing its affiliated coal mines as part of the CAA compliance plan if actual fuel costs are lower than fixed amounts stipulated in the settlement agreement. The shutdown costs could be substantial.

[See the discussion under "CSP" above regarding commission and legislative competitive initiatives within Ohio.]

Risks/Weaknesses

- The utilities' leverage is still higher than the average for their rating categories, although this is offset by the good-to-excellent competitive positions of those member utilities.
- Because of the lack of strong regulatory support in Virginia and West Virginia as well as the absence of rate cases in other jurisdictions, the utilities must rely upon cost cutting to improve financial ratios as business risks increase.
- Only average economic growth is expected across the system.

Opportunities/Strengths

- Low-cost, coal-fired generating capacity provides a competitive advantage.
- Completed construction cycles allow lower capital expenditures and reduced regulatory risk.
- Geographic reach and a balance between competitive initiatives and a conservative investment strategy position AEP to benefit from coming deregulation.

Financial Analysis

CONSOLIDATED — Consolidated cash flow coverage measures have improved over recent years while debt-to-total-capital ratios have remained fairly constant at 51%. Pre-tax interest coverage rose from 2.32 times in 1992 to 3.55 times in 1996. Through the first half of 1997 AEP subsidiaries have redeemed preferred stock totalling approximately $430 million through issuances of junior subordinated and long term debt. The debentures are debt, but over the short term provide some additional financial flexibility in allowing AEP subsidiaries to defer interest payments for up to five years. Declining fuel costs have offset rising non-fuel expenses, causing total operating expenses to remain generally flat, at 83% of revenues. Reinvestment of internally-generated cash will be supported by management's pursuit of a long-term payout ratio goal of 75%. Actual dividend payout for 1996 was 76.4% down from 84.2% in 1995.

AEP pursues a systemwide environmental compliance program. Requirements of Phases I and II of the Clean Air Act have been largely met through construction of the Gavin scrubbers at Ohio Power and through fuel switching. Environmental costs for the system between 1997 and 2001 are modest, totaling an estimated $109 million. Nearly all of this amount is targeted at modifying boilers to reduce nitrogen oxide emissions.

AP — Limited regulatory support, the largest share of construction expenditures in the AEP system, and dividends in excess of earnings have pressured leverage and coverage measures, resulting in a rating downgrade in 1996. The company expects construction to average $215 million per year over the next five years, three-quarters of which should be met through internal cash. AEP plans to provide equity contributions to allow a moderate decline in leverage and improvement in coverage over the next five years. Pre-tax interest coverage in 1996 was 2.87 times, an improvement from 1995 and approaching levels of the early 1990's. Long-term debt represents 51% of total capital. AP redeemed preferred stock amounting to nearly $184 million through the first six months of 1997 using proceeds from the issuance of junior subordinated debentures and first mortgage bonds. Total debt at the end of 1996 including short-term debt and the junior subordinated debt was 54% of total capital.

Actual construction expenditures may vary substantially from prior forecasts. The company has attempted to construct a high-voltage transmission line across western Virginia and southern West Virginia to serve growing retail load. The Virginia commission supports the construction. The U.S. Forest Service has opposed the construction based on its possible environmental impact. AP is negotiating with the appropriate parties to balance environmental concerns with needed transmission capacity. A swift resolution may not be forthcoming.

CSP — CSP's internal cash flow is expected to remain strong and more than ample to meet modest construction expenditures averaging $115 million per year over the next five years. Both coverage and leverage measures should continue to improve. Pre-tax interest coverage was 3.6 times in 1996 compared to 2.0 times in 1992. CSP redeemed $50 million of preferred stock in the first half of 1997 primarily through the issuance of junior subordinated debentures. Adjusted long-term debt was 57% of total capital at year end 1996. Dividend payout in 1996 was 75%.

I&M — Strong cash flow will continue to allow the company to meet its capital expenditures, estimated at $112 million per year over the next five years, out of internally-generated funds. Pre-tax interest coverage of 4.6 times in 1994, compared to 2.8 times in 1992, has continued to improve. I&M's balance sheet is somewhat leveraged by lease payments associated with its share of the Rockport plant. The adjusted debt level, reflecting leases and purchased power contracts, was 59% of total capital at year-end 1996. Through the first six months of 1997 I&M has redeemed 774,069 shares of preferred stock at a cost of approximately $78 million funded primarily through cash on hand.

The most recent estimates in 1994 of decommissioning costs for the Cook nuclear units ranged from $634 million to $988 million. These costs are being recovered in rates up to at least the lower end of the range.

KP — Total debt, at 59% of total capital in 1996, represents leverage higher than is typical for its rating category. KP's very competitive costs and rates plus its size within the AEP system offset the greater leverage. Both coverage and leverage measures are expected to remain stable over the intermediate term. Interest coverage in 1996 was 2.0 times. The company expects to meet only one-third of construction expenditures, expected to average $56 million over the next five years, through internal cash. Parent equity contributions are intended to support the construction program.

OP — The Gavin scrubber rate settlement in 1995 supports continued strong cash flow. The scrubber lease adds leverage to the balance sheet, however total adjusted debt remains in the mid-50% range and is expected to decline over the intermediate term. Unadjusted pre-tax interest coverage was a strong 5.0 times in 1996, substantially improved from 3.0 times in 1992, and is expected to continue to strengthen. Through June 30, 1997 OP had redeemed nearly $120 million in preferred stock funded by a combination of short-term debt and junior subordinated debentures.

OP owns three high-sulfur coal mines, two of which are likely to be closed to comply with Phase II of the CAA. OP may not be able to recover all of the estimated $195 million after-tax, non-Ohio-jurisdictional shutdown costs. However, the current rating outlook assumes OP has the ability to substantially recover these costs through the Gavin settlement agreement terms and to manage the financial impact of any unrecovered amounts.

Moody's Investors Service
Global Credit Research

Rating Review

December 22, 1997

A

American Electric Power Company, Inc.

Industry Group:	**ELECTRIC HOLDING CO.**
Contacts	
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Rating Category	**Moody's Rating**
American Electric Power Company, Inc.	
Commercial Paper	P-2*
Appalachian Power Company	
Sr. Secured 415 Shelf Registration	(P)A3*
Commercial Paper	P-2*
LT Counterparty Rating	Baa1*
First Mortgage Bonds	A3*
Jr. Sub. Deferrable Interest Debentures	Baa2*
Preferred/Preference Stock	"baa1"*
Secured MTN Program	A3*
Sr. Sec. Medium-Term Notes	A3*
Columbus Southern Power Company	
Commercial Paper	P-2*
LT Counterparty Rating	Baa1*
First Mortgage Bonds	A3*
Jr. Sub. Deferrable Interest Debentures	Baa2*
MTN Program	Baa1*
Medium Term Notes	Baa1*
Preferred/Preference Stock	"baa1"*
Secured MTN Program	A3*
Sr. Sec. Medium-Term Notes	A3*
Indiana Michigan Power Company	
415 Shelf Registration	(P)Baa1*
Commercial Paper	P-2*
Counterparty Rating	Baa2*
First Mortgage Bonds	Baa1*
Jr. Sub. Deferrable Interest Debentures	Baa3*
Preferred/Preference Stock	"baa2"*
S.F. Debenture	Baa2*
Secured MTN Program	Baa1*
Sr. Sec. Medium-Term Notes	Baa1*
Kentucky Power Company	
Sr. Secured 415 Shelf Registration	(P)Baa1*
Sr. Unsecured 415 Shelf Registration	(P)Baa2*
Commercial Paper	P-2*
LT Counterparty Rating	Baa2*
First Mortgage Bonds	Baa1*
Jr. Sub. Deferrable Interest Debentures	Baa3*

MTN Program	Baa1*
MTN Program	Baa2*
Medium Term Notes	Baa2*
Secured MTN Program	Baa1*
Ohio Power Company	
Preferred 415 Shelf Registration	(P)"baa1"*
Commercial Paper	P-2*
LT Counterparty Rating	Baa1*
Sr. Secured First Mortgage Bonds	A3*
Jr. Sub. Deferrable Interest Debentures	Baa2*
MTN Program	Baa1*
Medium Term Notes	Baa1*
Preferred/Preference Stock	"baa1"*
S.F. Debenture	Baa1*
Secured MTN Program	A3*
RGS (AEGCO) Funding Corporation	
Gtd. Sr. Sec.415 Shelf Registration	(P)Baa2*
Gtd. Sr. Sec. Lease Oblig. Bond	Baa2*
RGS (I&M) Funding Corporation	
Gtd. Sr. Sec. 415 Shelf Registration	(P)Baa2*
Gtd. Sr. Sec. Lease Oblig. Bond	Baa2*

*Rating confirmed

MOODY'S CONFIRMS AMERICAN ELECTRIC POWER AND CENTRAL AND SOUTH WEST RATINGS UPON MERGER ANNOUNCEMENT

Moody's Investors Service confirmed the ratings of American Electric Power Company, Central and South West Corporation, and all their operating subsidiaries, except Public Service of Oklahoma, after the two holding companies announced their intention to merge. They will form a new holding company, to be called American Electric Power Company, to serve 4.6 million customers in 11 states and four million customers in the UK. After the stock-for-stock merger, the combined companies are expected to have approximately $11.6 billion in debt and preferred stock outstanding. The companies share similar business and financial profiles, and their largest utilities carry identical ratings.

The combination's benefits arise more from longer-term strategic considerations than from near-term savings potential as their service territories are not contiguous. The companies have identified a relatively modest $2 billion in non-fuel operating savings to be achieved over 10 years. While the near-term cash flow impact is therefore modestly positive, the new American Electric Power will enjoy national scope, expanded customer bases and trading breadth, and a larger and more diversified generating base. Moody's notes that both companies have demonstrated similar visions for the future of the electric energy industry for several years.

The merger will require a number of regulatory approvals, but the companies anticipate obtaining these approvals over the next 12 to 18 months as they lack market power in the wholesale market. Current market structure in the UK may require the regulator to refer the combination, which will own two regional electricity companies (RECs), SEEBOARD and Yorkshire Electricity, to the Monopolies and Mergers Commission for review. Moody's anticipates a favorable outcome should that occur as most market participants and observers believe the UK's 12 RECs will need to consolidate to achieve further cost reductions.

Public Service Company of Oklahoma and its affiliate, PSO Capital I, were already under a rating review commenced when the utility reached a settlement agreement, later approved by the Oklahoma commission, to lower base rates $36 million annually. Moody's expects to complete that review in January.

American Electric Power ratings confirmed are:
American Electric Power Commercial Paper P-2
Appalachian Power Senior Secured A3
Long-Term Counterparty Baa1
Junior Subordinated Debt Baa2
Preferred Stock "baa1"
Columbus Southern Power Senior Secured A3
Sr Unsecured and LT Counterparty Baa1
Junior Subordinated Debt Baa2
Preferred Stock "baa1"
Indiana Michigan Power Senior Secured Baa1
Sr Unsecured and LT Counterparty Baa2
Junior Subordinated Debt Baa3
Preferred Stock "baa2"
Kentucky PowerSenior Secured Baa1
Sr Unsecured and LT Counterparty Baa2
Junior Subordinated Debt Baa3
Ohio PowerSenior Secured A3
Sr Unsecured and LT Counterparty Baa1
Junior Subordinated Debt Baa2
Preferred Stock "baa1"
RGS (AEGCO) Funding Corp Secured Lease Obligation Bonds Baa2
RGS (I&M) Funding Corp Secured Lease Obligation Bonds Baa2
Yorkshire Electricity Group plc Senior Unsecured Baa1
Commercial Paper P-2
Central and South West ratings confirmed:
Central and South West Corp Commercial Paper P-2
Central Power and Light Senior Secured A3
Long-Term Counterparty Baa1
Preferred Stock "baa1"
CPL Capital Hybrid Preferred"baa1"
Southwestern Electric Power Senior Secured Aa3
Long-Term Counterparty A1
Preferred Stock "a1"
SWEPCO Capital I Hybrid Preferred "aa3"
West Texas Utilities Senior Secured A2
Long-Term Counterparty A3
Preferred Stock "a3"
CSW Credit Commercial Paper P-1
CSW Investments Senior Secured Bank Facility Baa2
Senior Unsecured Baa2
SEEBOARD plc Senior Unsecured Baa1
Commercial Paper P-2
CSW Energy Backed Senior Unsecured Baa2
Orange Cogen Funding Corp Backed Senior Secured Baa3
Remaining under review for possible downgrade are:
Public Service Co of Oklahoma Senior Secured Aa3
Long-Term Counterparty A1
Preferred Stock "a1"
PSO Capital I Hybrid Preferred "aa3"

BN 17:50 (MDY)-AMERICAN ELECTRIC POWER RATINGS CONFIRMED BY MOODY'S

he following is provided by Moody's Investors Service.)

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MOODY'S CONFIRMS AMERICAN ELECTRIC POWER AND CENTRAL AND SOUTH WEST RATINGS UPON MERGER ANNOUNCEMENT

Continues Review of Public Service Company of Oklahoma and PSO Capital I

New York, December 22, 1997 -- Moody's Investors Service confirmed the ratings of American Electric Power Company, Central and South West Corporation, and all their operating subsidiaries, except Public Service of Oklahoma, after the two holding companies announced their intention to merge. They will form a new holding company, to be called American Electric Power Company, to serve 4.6 million customers in 11 states and ur million customers in the UK. After the stock-for-stock merger, the combined companies are expected to have approximately $11.6 billion in debt and preferred stock outstanding. The companies share similar business and financial profiles, and their largest utilities carry identical ratings.

The combination's benefits arise more from longer-term strategic considerations than from near-term savings potential as their service territories are not contiguous. The companies have identified a relatively modest $2 billion in non-fuel operating savings to be achieved over 10 years. While the near-term cash flow impact is therefore modestly positive, the new American Electric Power will enjoy national scope, expanded customer bases and trading breadth, and a larger and more diversified generating base. Moody's notes that both companies have demonstrated similar visions for the future of the electric energy industry for several years.

The merger will require a number of regulatory approvals, but the companies anticipate obtaining these approvals over the next 12 to 18 months as they lack market power in the wholesale market. Current market structure in the UK may require the regulator to refer the combination, which will own two regional electricity companies (RECs), SEEBOARD and Yorkshire Electricity, to the Monopolies and Mergers Commission for

-view. Moody's anticipates a favorable outcome should that cur as most market participants and observers believe the UK's 12 RECs will need to consolidate to achieve further cost reductions.
Public Service Company of Oklahoma and its affiliate, PSO Capital I, were already under a rating review commenced when the utility reached a settlement agreement, later approved by the Oklahoma commission, to lower base rates $36 million annually. Moody's expects to complete that review in January.

American Electric Power ratings confirmed are:
American Electric Power Commercial Paper -- P-2
Appalachian Power Senior Secured -- A3
Long-Term Counterparty -- Baa1
Junior Subordinated Debt -- Baa2
Preferred Stock -- "baa1"
Columbus Southern Power Senior Secured -- A3
Sr. Unsecured and LT Counterparty -- Baa1
Junior Subordinated Debt -- Baa2
Preferred Stock -- "baa1"
Indiana Michigan Power Senior Secured -- Baa1
Sr. Unsecured and LT Counterparty -- Baa2
Junior Subordinated Debt -- Baa3
Preferred Stock -- "baa2"
Kentucky Power Senior Secured -- Baa1
Sr. Unsecured and LT Counterparty -- Baa2
unior Subordinated Debt -- Baa3
Ohio Power Senior Secured -- A3
Sr. Unsecured and LT Counterparty -- Baa1
Junior Subordinated Debt -- Baa2
Preferred Stock -- "baa1"
RGS (AEGCO) Funding Corp. Secured Lease Obligation Bonds -- Baa2
RGS (I&M) Funding Corp. Secured Lease Obligation Bonds -- Baa2
Yorkshire Electricity Group plc Senior Unsecured -- Baa1
Commercial Paper -- P-2

Central and South West ratings confirmed:
Central and South West Corp. Commercial Paper -- P-2
Central Power and Light Senior Secured -- A3
Long-Term Counterparty -- Baa1
Preferred Stock -- "baa1"
CPL Capital Hybrid Preferred -- "baa1"
Southwestern Electric Power Senior Secured -- Aa3
Long-Term Counterparty -- A1
Preferred Stock -- "a1"
SWEPCO Capital I Hybrid Preferred -- "aa3"
West Texas Utilities Senior Secured -- A2
Long-Term Counterparty -- A3
Preferred Stock -- "a3"

CSW Credit Commercial Paper -- P-1
CSW Investments Senior Secured Bank Facility -- Baa2
Senior Unsecured -- Baa2
SEEBOARD plc Senior Unsecured -- Baa1
Commercial Paper -- P-2
CSW Energy Backed Senior Unsecured -- Baa2
Orange Cogen Funding Corp. Backed Senior Secured -- Baa3

Remaining under review for possible downgrade are:
Public Service Co. of Oklahoma Senior Secured -- Aa3
Long-Term Counterparty -- A1
Preferred Stock -- "a1"
PSO Capital I Hybrid Preferred -- "aa3"

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Attachment
Page 97 of 141
KPSC Case No. 99-149
KESI's (2nd Set)
Supplemental Request for Information
Item No. 17

PRN DCR REAFFIRMS AEP, CSW AND SUBSIDIARIES FOLLOWING MERGER AGREEME
Dec 22 1997 15:33

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CHICAGO, Dec. 22 /PRNewswire/ -- Duff & Phelps Credit Rating Co. (DCR) has reaffirmed the credit ratings of American Electric Power Company, Inc. (AEP) and Central and South West Corp. (CSW) (NYSE: CSR) and their subsidiaries/affiliates following the announcement that AEP and CSW would merge under a definitive merger agreement. The transaction is structured as a tax-free, stock-for-stock transaction that will be accounted for as a pooling of interests. Under the terms of the agreement, each share of CSW common stock will be converted into 0.6 common shares of AEP; AEP will issue approximately $6.6 billion in common stock to CSW shareholders in connection with the merger.

DCR views the merger as positive. The merger is both strategic and synergistic, as it greatly expands the size and reach of the proposed company. The combination is expected to result in cost savings of approximately $2.0 billion over a 10-year period through the elimination of duplicate corporate and administration functions, and improved operating productivity. Through these cost savings, coupled with expected revenue enhancements, the combined entity should enjoy stronger operating cash flow. Free cash flow is also expected to be healthier primarily as a result of the combined company's expected dividend policy. The merger will create a diversified electric utility holding company with combined revenue of approximately $11.0 billion and a total market capitalization of approximately $28.1 billion, and will serve more than 4.6 million customers in 11 states in the United States and 4 million customers outside of the United States. The transaction will require several state and federal regulatory approvals, which management expects will take between 12 and 18 months.

DCR reaffirms the credit ratings of AEP and CSW and their subsidiaries as follows.

American Electric Power Company Inc.	
Commercial Paper	'D-2'(D-Two)
Implied Senior Debt	'BBB+(Triple-B-Plus)
Appalachian Power Company	
FMBs/Sec. MTNs	'A'(Single-A)
Jr. Sub. Debs.	'A-'(Single-A-Minus)
Pfd. Stk.	'BBB+'(Triple-B-Plus)
Commercial Paper	'D-1'(D-One)
Columbus Southern Power Company	
FMBs/Sec. MTNs	'A'(Single-A)
Notes/Debs.	'A-'(Single-A-Minus)
Jr. Sub Debs.	'A-'(Single-A-Minus)

Pfd. Stk.	'BBB+'(Triple-B-Plus)
Commercial paper	'D-1'(D-One)
Ohio Power Company	
FMBs	'A'(Single-A)
Notes/Debs.	'A-'(Single-A-Minus)
Jr. Sub. Debs.	'BBB+'(Triple-B-Plus)
Pfd. Stk.	'BBB'(Triple-B)
Commercial paper	'D-1'(D-One)
Yorkshire Electricity Group, plc	
Eurobonds	'BBB+'(Triple-B-Plus)
Yorkshire Power Group Ltd.	
Implied Senior Unsecured	'BBB+'(Triple-B-Plus)
Commercial Paper	'D-2'(D-Two)
Central and South West Corporation	
Commercial Paper	'D-2'(D-Two)
Central Power and Light Company	
FMBs/Coll. PCRBs	'A'(Single-A)
Non-Coll. PCRBs	'A-'(Single-A-Minus)

PCRBs - MBIA	'AAA'(Triple-A)
Pfd. Stk./Trust Pfd.	'BBB+'(Triple-B-Plus)
Public Service Co. of Oklahoma	
FMBs	'AA-'(Double-A-Minus)
Non-Coll. PCRBs	'A+'(Single-A-Plus)
PCRBs - MBIA	'AAA'(Triple-A)
Pfd. Stk./Trust Pfd.	'A+'(Single-A-Plus)
Southwestern Electric Power Co.	
FMBs	'AA'(Double-A)
Non-Coll. PCRBs	'AA-'(Double-A-Minus)
Pfd. Stk./Trust Pfd.	'AA-'(Double-A-Minus)
West Texas Utilities	
FMBs	'A+'(Single-A-Plus)
PCRBs - MBIA	'AAA'(Triple-A)
Pfd. Stk./Trust Pfd.	'A'(Single-A)
SEEBOARD, plc	
Eurobonds	'A-'(Single-A-Minus)
Implied Short-Term	'D-1-'(D-One-Minus)

CSW Investments, Inc.	
Eurobonds	'A-'(Single-A-Minus)
Yankee Bonds	'A-'(Single-A-Minus)
Implied Short-Term	'D-1-' (D-One-Minus)
CSW Energy, Inc.	
Secured Notes	'BBB+'(Triple-B-Plus)
Orange Cogen Funding Corp.	
Sr.Sec. Bonds	'BBB'(Triple-B)
CSW Credit, Inc.	
Commercial Paper	'D-1+' (D-One-Plus)

American Electric Power is a public utility holding company for seven electric utility companies serving nearly 3 million retail customers in seven states, and a variety of nonregulated businesses involved in the energy industry. Major nonregulated investments include its 50 percent ownership of Yorkshire, a fast-growing power marketing subsidiary and interests in various domestic and international power generation projects.

Central and South West Corporation is an electric utility holding company for four U.S. electric utilities and a regional electricity company in the United Kingdom. CSW's other non-regulated businesses include: CSW Energy and

CSW International, two companies that invest in independent power projects, electric distribution businesses and other energy-related projects both domestically and internationally and CSW Credit, a factoring company that purchases account receivables from CSW's U.S. electric utilities and other non-affiliates on a non-recourse basis.

SOURCE Duff & Phelps Credit Rating Co.
-0- 12/22/97
/CONTACT: Daniel R. Kastholm, CFA, 312-368-2070, kastholm@dcrco.com, Jason T. Todd, 312-368-3217, todd@dcrco.com, Brian M. Youngberg, 312-368-3332, youngberg@dcrco.com, John W. O'Connor, 312-368-2059, or oconnor@dcrco.com all of Duff & Phelps/
(CSR)

CO: American Electric Power Company, Inc.; Central and South West Corp.
ST: Texas
IN: OIL
SU: RTG

-0- (PRN) Dec/22/97 15:18
EOS (PRN) Dec/22/97 15:18 **

PRN 12/24 S&P RATINGS UNCHANGED ON AEP & CENTRAL AND SOUTHWEST CORP

NEW YORK, Dec. 24 /PRNewswire/ -- Standard & Poor's is not taking any rating action at this time on the ratings and stable outlooks (see list below) on the operating units of American Electric Power Co. Inc. (AEP) and related entities, and on Central and South West Corp. units (CSR) and related entities, following the proposed merger of the two companies. However, this is pending a full review with both management teams in early January 1998 regarding their financial and operating strategies and objectives.

After this meeting, possible rating actions would include outlook revisions or even CreditWatch listings. Furthermore, Standard & Poor's will evaluate management's approach to insulate the individual utilities from the activities of the corporate parent. This is important because, given the wide spread of ratings on entities in both companies, Standard & Poor's would usually be inclined to have the operating units rated closer to the combined consolidated credit assessment, especially when operating and financing functions are centralized, Standard & Poor's said. -- CreditWire

CENTRAL AND SOUTH WEST CORP.	
Commercial paper	A-2
CENTRAL POWER & LIGHT CO.	
Corporate credit rating	A
Senior secured. debt	A
Senior unsecured debt	A-
Preferred stock	A-
PUBLIC SERVICE CO. OF OKLAHOMA	
Corporate credit rating	A+
Senior secured. debt	AA-
Senior unsecd. debt	A
Preferred stock	A
SOUTHWESTERN ELECTRIC POWER CO.	
Corporate credit rating	A+
Senior secured debt	AA-
Senior unsecured debt	A

Preferred stock	A
WEST TEXAS UTILITIES CO.	
Corporate credit rating	A
Senior secured. debt	A
Senior unsecured debt	A-
Preferred stock	A-
CSW INVESTMENTS	
Corporate credit rating	A-
Senior unsecured debt	A-
SEEBOARD PLC	
Corporate credit rating	A-
Senior unsecured debt	A-
CSW ENERGY INC.	
Corporate credit rating	BBB+
Senior unsecured debt	BBB+
CSW CREDIT INC.	
Commercial Paper	A-1+
American Electric Power	
APPALACHIAN POWER CO.	
Corporate credit rating	A-
Senior secured debt	A
Senior unsecured debt	BBB+
Junior Subordinated	BBB+
Preferred stock	BBB+
INDIANA MICHIGAN POWER CO.	

Corporate credit rating	BBB+
Senior secured debt	A-
Senior unsecured debt	BBB
Subordinated	BBB
Junior Subordinated	BBB
Preferred stock	BBB
RGS (I&M) FUNDING CORP	
Corporate credit rating	BBB
Senior unsecured debt	BBB
KENTUCKY POWER CO.	
Corporate credit rating	BBB+
Senior secured debt	A
Senior unsecured debt	BBB
Subordinated	BBB
OHIO POWER CO.	
Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+
Subordinated	BBB+
Preferred stock	BBB+
RGS (EAGCO) FUNDING CORP.	
Corporate credit rating	BBB
Senior unsecured debt	BBB
COLUMBUS SOUTHERN POWER CO.	

Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+
Subordinated	BBB+
Preferred stock	BBB+
COLUMBUS & SOUTHERN OHIO ELECTRIC CO.	
Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+

SOURCE Standard & Poor's CreditWire
-0- 12/24/97
/CONTACT: Steve Zimmerman, 212-208-1658 or Judith Waite, 212-208-1663 or Todd A Shipman, CFA, 212-208-8704 all of Standard & Poor's/
/Web site: www.ratings.standardpoor.com/

CO: American Electric Power Co. Inc.; Central and South West Corp.
ST: New York
:: FIN
SU: RTG
-0- (PRN) Dec/24/97 14:22
EOS (PRN) Dec/24/97 14:22 **

-0- (PRN) Dec/24/97 14:37

PRN 01/06 S&POUTLOOK ON AMERICAN ELECTRIC POWER UNITS NOW POSITIVE;

Central & South West Negative

NEW YORK, Jan. 6 /PRNewswire/ -- Standard & Poor's today revised its rating outlooks on the operating units of American Electric Power Inc. (AEP) (NYSE: AEP) to positive from stable and affirmed its ratings on these entities.

Standard & Poor's also revised its rating outlooks on Central & South West Corp.'s (CSR) (NYSE: CSR) regulated U.S. units to negative from stable and affirmed its ratings on these utilities. The ratings on AEP's and CSR's other investments are affirmed (see list of all ratings below).

The outlook revisions reflect the proposed acquisition of CSR by AEP.

Under the proposed organizational structure, whereby AEP would become the parent of CSR's operating units, Standard & Poor's preliminary expectation is that the credit ratings at the individual utilities would be clustered around the low single-'A' category. Some rating distinctions could occur recognizing elements of insulation, such as regulatory oversight, which protect the cash and financial profile of individual utilities. Thus, given the wide spread between the existing ratings of the two companies, the outlook revisions reflect the possibility of rating changes, if the acquisition receives the required regulatory approvals.

Standard & Poor's analysis upon the transaction's completion will incorporate the positive attributes created by the merger, including the vast domestic service territory and expanded regulatory and fuel diversity. The combination's substantial critical mass of customers, low-cost power generation, and transmission capacity also will help the creation of a national energy trading operation. The high business risk and thin profit margins associated with energy trading could challenge management and will necessitate an appropriate level of financial performance and capitalization. In addition, increasing investments in overseas energy projects may heighten the consolidated credit risk profile.

CENTRAL & SOUTH WEST CORP. UNITS:
OUTSTANDING RATINGS AFFIRMED; OUTLOOK REVISED TO NEGATIVE

	Rating
Central Power & Light Co.	
Corporate credit rating	A
Senior secured debt	A
Senior unsecured debt	A-
Preferred stock	A-
Public Service Co. of Oklahoma	
Corporate credit rating	A+
Senior secured debt	AA-
Senior unsecured debt	A
Preferred stock	A
Southwestern Electric Power Co.	
Corporate credit rating	A+

Senior secured debt	AA-
Senior unsecured debt	A
Preferred stock	A

West Texas Utilities Co.

Corporate credit rating	A
Senior secured debt	A
Senior unsecured debt	A-
Preferred stock	A-

OUTSTANDING RATINGS AFFIRMED; OUTLOOK STABLE

Central & South West Corp.*

Commercial paper	A-2

CSW Investments

Corporate credit rating	A-
Senior unsecured debt	A-

Seeboard PLC

Corporate credit rating	A-
Senior unsecured debt	A-

CSW Energy Inc.

Corporate credit rating	BBB+
Senior unsecured debt	BBB+

CSW Credit Inc.*

Commercial paper	A-1+

AMERICAN ELECTRIC POWER CORP. UNITS:
OUTSTANDING RATINGS AFFIRMED; OUTLOOKS REVISED TO POSITIVE

Appalachian Power Co.

Corporate credit rating	A-
Senior secured debt	A
Senior unsecured debt	BBB+
Junior subordinated debt	BBB+
Preferred stock	BBB+

Indiana Michigan Power Co.

Corporate credit rating	BBB+
Senior secured debt	A-
Senior unsecured debt	BBB
Subordinated debt	BBB
Junior subordinated debt	BBB

Preferred stock	BBB
RGS (I&M) Funding Corp.	
Corporate credit rating	BBB
Senior unsecured debt	BBB
Kentucky Power Co.	
Corporate credit rating	BBB+
Senior secured debt	A
Senior unsecured debt	BBB
Subordinated debt	BBB
Ohio Power Co.	
Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+
Subordinated debt	BBB+
Preferred stock	BBB+
RGS (AEGCO) Funding Corp.	
Corporate credit rating	BBB
Senior unsecured debt	BBB
Columbus Southern Power Co.	
Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+
Subordinated debt	BBB+
Preferred stock	BBB+
Columbus & Southern Ohio Electric Co.	
Corporate credit rating	A-
Senior secured debt	A-
Senior unsecured debt	BBB+

AMERICAN ELECTRIC POWER CORP. RELATED ENTITY:
OUTSTANDING RATINGS AFFIRMED; OUTLOOK STABLE

Yorkshire Electricity Group PLC	
Corporate credit rating	BBB+
Senior unsecured debt	BBB+
Commercial paper	A-2

*Outlook revision not applicable to short-term debt.

SOURCE Standard & Poor's CreditWire

-0- 01/06/98

/CONTACT: John J Bilardello, 212-208-1525, or Judith Waite, 212-208-1663, or Steve Zimmerman, 212-208-1658, or Todd A Shipman, CFA, 212-208-8704, all of Standard & Poor's/

/Web site: http://www.ratings.standardpoor.com/
(AEP CSR)

CO: American Electric Power Inc.; Central & South West Corp.
ST: New York
IN: FIN
SU: RTG

-0- (PRN) Jan/06/98 18:17
EOS (PRN) Jan/06/98 18:17 **

-0- (PRN) Jan/06/98 18:32

PSO

SPC 15:15 S&P Revises Ratings of Utility First Mortgage Bonds

NY -- Standard & Poor's CreditWire 10/14/97 -- Standard & Poor's has incorporated into its ratings of corporate issues a more vigorous analysis of ultimate recovery potential to supplement the analysis of default risk. This is consistent with the policies recently established for all secured debt. The incorporation of ultimate recovery risk is particularly important for ratings of electric, gas, and water utility first mortgage bonds, general and refunding bonds, or otherwise-designated senior secured debt. If, in Standard & Poor's analytical conclusion, full recovery of principal can be anticipated in a post-default scenario -- albeit delayed -- an issue's rating may be enhanced one or two notches above the corporate credit rating (CCR) or default rating. (Please refer to the attached list.) Until now, a utility's first mortgage bond ratings have been determined by the CCR.

For highly rated issuers, the probability of default is low, so the relevance of post-default recovery and, consequently, its weighting in the analysis are relatively small. In these cases, it would be unusual to find first mortgage bonds enhanced by a rating of more than one notch above the CCR.

First mortgage bondholders benefit from a first position priority lien on substantially all of the utility's property and franchises owned or thereafter acquired. Besides the asset protection, the mortgage indenture contains a fairly restrictive covenant package, including a limitation on the issuance of additional secured bonds based on both interest coverage and debt level tests.

The extent of any enhancement of a utility's first mortgage bond rating depends on collateral values relative to the maximum amount of first mortgage bonds that may be outstanding at any one time under the terms of the indenture (more specifically, the bonding ratio and retired bond credit mechanisms). Because the outcome for creditors going into the workout process is ultimately a function of the value of their collateral, developing a sense of this value acts as an appropriate proxy for just how well the creditors are secured.

The analysis does not attempt to specifically predict the ultimate outcome of any bankruptcy proceeding. Rather, the recovery risk profile is established by assessing the characteristics of various types of utility assets used as collateral: electric generation, transmission, distribution, gas transmission and distribution, water, etc. Higher collateral coverage levels increase confidence that asset values will cover the secured debt.

Utility assets are vested with a particular value because of the fundamental role that they perform in the health of all phases of the economy, especially the transmission and distribution delivery system infrastructure. There is an inherent value in these assets that is largely independent of the owner's financial condition.

Therefore, in stressing asset values, Standard & Poor's is more liberal in its attribution of collateral value to the electric, gas, and water delivery assets than to production assets. Furthermore, distinctions are made to differentiate companies on the basis of the relative efficiency of their non-nuclear generating plants, as measured by total variable production costs. Nuclear assets are given zero collateral value.

Standard & Poor's will address the appropriateness of an upgrade for any company whose first mortgage bond rating is on CreditWatch with negative implications at the time that the CreditWatch listing is resolved. Also, there may be companies that are excluded from the list because of indenture and collateral information that is insufficient to make an ultimate recovery decision.

All CCRs and outlooks of the following companies are affirmed. Standard & Poor's will maintain ongoing surveillance with regard to the issue ratings. -- CreditWire

ELECTRIC UTILITY	SENIOR SECURED DEBT To	From
Appalachian Power Co.	A	A-
Arizona Public Service Co.	A-	BBB+
Baltimore Gas & Electric Co.	AA-	A+
Black Hills Corp.	A+	A
Central Louisiana Electric Co.	A+	A
Central Vermont Public Service Corp.	A-	BBB
Consumers Energy Co.	BBB+	BBB-
Detroit Edison Co.	A-	BBB+
Duke Energy Co.	AA-	A+
Entergy Arkansas Inc.	BBB+	BBB
Entergy Mississippi Inc.	BBB+	BBB
Green Mountain Power Corp.	A-	BBB+
Gulf Power Co.	AA-	A+
Hawaiian Electric Co.	A-	BBB+
Idaho Power Co.	AA-	A+
IES Utilities Inc.	A+	A
Indiana Michigan Power Co.	A-	BBB+
Jersey Central Power & Light Co.	A-	BBB+
Kentucky Power Co.	A	BBB+
Kentucky Utilities Co.	AA	AA-
Long Island Lighting Co.	BBB	BBB-
Massachusetts Electric Co.	AA-	A+
Metropolitan Edison Co.	A-	BBB+
Midwest Power Systems Inc. (MidAmerican Energy Co.)	AA-	A+
Minnesota Power & Light Co.	A	BBB+
Montana Power Co.	A-	BBB+
Narragansett Electric Co.	AA-	A+
Nevada Power Co.	A-	BBB
Niagara Mohawk Power Corp.	BB+	BB
Northern Indiana Public Service Co.	A+	A
Northern States Power Minnesota	AA	AA-
Ohio Edison Co.	BBB-	BB+
Oklahoma Gas & Electric Co.	AA	AA-
Pacific Gas & Electric Co.	AA-	A+
Pennsylvania Electric Co.	A	A-
Public Service Co. of Colorado	A	A-
Public Service Co. of Oklahoma	AA-	A+
Savannah Electric & Power Co.	AA-	A+
Southwestern Electric Power Co.	AA-	A+
St. Joseph Light & Power Co.	A	A-
Texas-New Mexico Power Co.	BBB	BB+
Tucson Electric Power Co.	BB+	BB-

Western Resources Inc.	A-	BBB+
GAS UTILITY		
Colonial Gas Co.	A	A-
Commonwealth Gas Co.	A	A-
New Jersey Natural Gas Co.	A+	A
PG Energy Co.	A-	BBB
Providence Gas Co.	A	BBB+
South Jersey Gas Co.	A	BBB+
Southern Connecticut Gas Co.	A	A-
Valley Gas Co.	A	BBB+
WATER UTILITY		
Indianapolis Water Co.	A+	A
Middlesex Water Co.	A+	A
New Jersey-American Water Co.	A+	A
Pennsylvania-American Water Co.	A	A-
Philadelphia Suburban Water Co.	AA-	A+
St. Louis County Water Co.	A	A-
United Water New Jersey	A+	A

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Ronald M Barone, New York (1) 212-208-1929
John J Bilardello, New York (1) 212-208-1525

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AMERICAN ELECTRIC POWER SUBSIDIARY RATINGS

	Moody's	S&P	Fitch	D&P
Senior Secured Debt/First Mortgage Bonds				
AP	A3	A	A	A
CSP	A3	A-	A-	A
I&M	Baa1	A-	BBB+	n/a
KP	Baa1	A	BBB+	n/a
OP	A3	A-	A-	A
Senior Unsecured Debt/Debentures				
AEG				
RGS (AEG)	Baa2	BBB	BBB	BBB
AP	Baa1	BBB+	A-	A-
I&M	Baa2	BBB	BBB	n/a
RGS (I&M)	Baa2	BBB	BBB	n/a
OP	Baa1	BBB+	BBB+	BBB+
Gavin Operating Lease	n/a	n/a	n/a	A-
Junior Subordinated Deferrable Interest Debentures				
AP	Baa2	BBB+	n/a	A-
CSP	Baa2	BBB+	BBB+	A-
I&M	Baa3	BBB	n/a	n/a
KP	Baa3	BBB	BBB-	n/a
OP	Baa2	BBB+	n/a	BBB+
Preferred Stock				
AP	"baa1"	BBB+	A-	BBB+
CSP	"baa1"	BBB+	BBB+	BBB+
I&M	"baa2"	BBB	BBB	n/a
OP	"baa1"	BBB+	BBB+	BBB
Commercial Paper				
AEP	P-2	n/a	F-2	D-2
AP	P-2	n/a	F-1	D-1
CSP	P-2	n/a	F-1	D-1
I&M	P-2	n/a	F-2	n/a
KP	P-2	n/a	F-2	n/a
OP	P-2	n/a	F-2	D-1

Note change: S&P raised APCo's senior secured debt rating to A from A-; raised I&M's senior secured debt rating to A- from BBB+; and raised KPCo's senior secured debt rating to A from BBB+.

10/97
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AMERICAN ELECTRIC POWER
SUBSIDIARY RATINGS

	Moody's	S&P	Fitch	D&P
Senior Secured Debt/First Mortgage Bonds				
AP	A2	A-	A	A
CSP	Baa1	A-	BBB+	BBB+
I&M	Baa1	BBB+	BBB+	BBB+
KP	Baa1	BBB+	BBB+	BBB
OP	A3	A-	A-	A
Senior Unsecured Debt/Debentures				
AEG				
RGS (AEG)	Baa2	BBB	BBB	BBB
AP	A3	BBB+	A-	A-
I&M	Baa2	BBB	BBB	BBB-
RGS (I&M)	Baa2	BBB	BBB	BBB
OP	Baa1	BBB+	BBB+	BBB+
Gavin Operating Lease	n/a	n/a	n/a	A-
Junior Subordinated Deferrable Interest Debentures				
CSP	Baa3	BBB+	n/a	BBB
KP	Baa3	BBB	n/a	n/a
OP*	Baa2	BBB+	n/a	n/a
Preferred Stock				
AP	a3	BBB+	A-	A-
CSP	baa2	BBB+	BBB	BBB
I&M	baa2	BBB	BBB	BBB-
OP	baa1	BBB+	BBB+	BBB+
Commercial Paper				
AEP	P-2	n/a	F-2	D-2
AP	P-1	n/a	F-1	D-1
CSP	P-2	n/a	F-2	D-2
I&M	P-2	n/a	F-2	D-2
KP	P-2	n/a	F-2	D-2
OP	P-2	n/a	F-2	D-1

• Preliminary

9/29/95

AMERICAN ELECTRIC POWER
SUBSIDIARY DEBT, PREFERRED STOCK, AND COMMERCIAL PAPER RATINGS

First Mortgage Bonds

	Moody's	S&P	Fitch	D&P
AP	A2	A-	A	A
CSP	Baa2	BBB+	BBB	BBB
I&M	Baa1	BBB+	BBB+	BBB
KP	Baa1	BBB+	BBB+	BBB+
OP	A3	A-	A-	A

Debentures

	Moody's	S&P	Fitch	D&P
AP	A3	BBB+	A-	A-
I&M	Baa2	BBB	BBB	BBB-
OP	Baa1	BBB+	BBB+	A-

Preferred Stock

	Moody's	S&P	Fitch	D&P
AP	a3	BBB+	A-	A-
CSP	baa3	BBB-	BBB-	BBB-
I&M	baa2	BBB	BBB	BBB-
OP	baa1	BBB+	BBB+	A-

Commercial Paper

	Moody's	S&P	Fitch	D&P
AEP	P-2		F-2	
AP	P-1		F-1	
CSP	P-2		F-2	
I&M	P-2		F-2	
KP	P-2		F-2	
OP	P-2		F-1	

Note change: S&P raised Columbus Southern Power ratings on first mortgage bonds and secured medium-term notes to BBB+ from BBB, debentures and unsecured pollution control revenue bonds to BBB from BBB-, and confirmed its cumulative preferred stock rating of BBB- and removed the rating from Credit Watch.

8/20/93

SUBSIDIARY DEBT, PREFERRED STOCK, AND COMMERCIAL PAPER RATINGS

First Mortgage Bonds

	Moody's	S&P	Fitch	D&P
AP	A2	A-	A	A
CSP	Baa2	BBB	BBB	BBB
I&M	Baa1	BBB+	BBB+	BBB
KP	Baa1	BBB+	BBB+	BBB+
OP	A2	A-	A	A

Debentures

	Moody's	S&P	Fitch	D&P
AP	A3	BBB+	A-	A-
I&M	Baa2	BBB	BBB	BBB-
OP	A3	BBB+	A-	A-

Preferred Stock

	Moody's	S&P	Fitch	D&P
AP	a3	BBB+	A-	A-
CSP	baa2	BBB-	BBB-	BBB-
I&M	baa2	BBB	BBB	BBB-
OP	a3	BBB+	A-	A-

Commercial Paper

	Moody's	Fitch
AEP	P-2	F-2
AP	P-1	F-1
CSP	P-2	F-2
I&M	P-2	F-2
KP	P-2	F-2
OP	P-1	F-1

Note change: D&P - ratings for Appalachian Power lowered:

Debt from A+ to A
Debs from A+ to A-
Pref. Stock from A to A-

2/7/92

SUBSIDIARY DEBT, PREFERRED STOCK, AND COMMERCIAL PAPER RATINGS

First Mortgage Bonds

	Moody's	S & P	Fitch	D&P	MCM
AP	A2	A-	A	A+	A-
CSP	Baa2	BBB	BBB	BBB	BBB-
I&M	Baa1	BBB+	BBB+	BBB	BBB
KP	Baa1	BBB+	BBB+	BBB+	BBB
OP	A2	A-	A	A	A-

Debentures

	Moody's	S & P	Fitch	D&P	MCM
AP	A3	BBB+	A-	A+	n/a
CSP	Baa3	BBB-	BBB-	BBB-	n/a
I&M	Baa2	BBB	BBB	BBB-	n/a
OP	A3	BBB+	A-	A-	n/a

Preferred Stock

	Moody's	S & P	Fitch	D&P	MCM
AP	a3	BBB+	A-	A	BBB-
CSP	baa2(1)	BBB-(2)	BBB-(2)	BB+(3)	BB-
I&M	baa2	BBB	BBB	BBB-	BB
OP	a3	BBB+	A-	A-	BBB-

(1) Preference shares: baa3
(2) Preference shares: BB+
(3) Preference shares: BB

Commercial Paper

	Moody's	Fitch	MCM
AEP	P-2	F-2	
AP	P-1	F-1	3*
CSP	P-2	F-2	4*
I&M	P-2	F-2	4*
KP	P-2	F-2	3*
OP	P-1	F-1	3*

*Short-term debt rating

NOTE
CHANGE: MCM - ratings for Kentucky Power First Mortgage Bonds upgraded from BBB- to BBB and short-term debt from 4 to 3.

8/2/89

Commercial Customer Group
First Set of Requests
Question 1-5

Resonse
The following table shows the requested bond and stock ratings, for CSW and subsidiaries, in the Company's possession.

	Current 1998	EOY 1997	EOY 1996	EOY 1995	EOY 1994	EOY 1993	EOY 1992	EOY 1991	EOY 1990	EOY 1989	EOY 1988
Duff & Phelps											
First Mortgage Bond Rating											
Central Power and Light Company	A	A	A	A	A	A	A	A	BBB+	BBB+	BBB+
Public Service Company of Oklahoma	AA-	AA	AA	AA	AA	AA	AA	AA	AA	AA	AA
Southwestern Electric Power Company	AA	AA+	AA+	AA+	AA+	AA+	AA+	AA+	AA+	AA+	AA+
West Texas Utilities Company	A+	A+	AA-	AA-	AA	AA	AA	AA	AA	AA	AA
SEEBOARD (Eurobond)	A-	A-	A-	NA	NA	NA	NA	NA	NA	NA	NA
Commercial Paper Rating											
Central and South West Corporation	D-2	D-1	D-1	D-1	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+
CSW Credit	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+	D-1+
SEEBOARD	D-1-	D-1-	D-1-	NR							
Preferred Stock Rating											
Central Power and Light Company	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	BBB	BBB	BBB
Public Service Company of Oklahoma	A+	AA-	AA-	AA-	AA-	AA	AA	AA	AA	AA	AA
Southwestern Electric Power Company	AA-	AA	AA	AA	AA	AA	AA	AA	AA	AA	AA
West Texas Utilities Company	A	A	A+	A+	AA-	AA-	AA-	AA-	AA-	AA-	AA-
Fitch Ratings	CSW and its subsidiaries are not rated by Fitch										
Standard & Poor's											
Common Stock Rating	B+	A-	A-	A-	A-	A	A	A	A		
First Mortgage Bond Rating											
Central Power and Light Company	A	A	A	A	A	A	A	A-	A-	A-	A-
Public Service Company of Oklahoma	AA-	AA-	A+	A+	A+	AA-	AA-	AA-	AA-	A+	A+
Southwestern Electric Power Company	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	A+	A+
West Texas Utilities Company	A	A	A+	A+	A+	AA-	AA-	AA-	AA-	A+	A+
SEEBOARD (Eurobond)	A-	A-	A-								
Commercial Paper Rating											
Central and South West Corporation	A-2	A-2	A-2	NR	NR	NR	NR	NR	NR	NR	NR
CSW Credit	A-1+	A-1+	NR	NR	NR	NR	NR	NR	NR	NR	NR
SEEBOARD	A-2	A-2	A-2	A-1+							
Preferred Stock Rating											
Central Power and Light Company	A-	A-	A-	A-	A-	A-	A-	BBB+	BBB+	BBB+	BBB+
Public Service Company of Oklahoma	A	A	A	A	A	A+	A+	A+	A+	A	A
Southwestern Electric Power Company	A	A	A+	A+	A+	A+	A+	A+	A+	A	A
West Texas Utilities Company	A-	A-	A	A	A	A+	A+	A+	A+	A	A
CSW Common Stock Rating											
Moody's											
First Mortgage Bond Rating											
Central Power and Light Company	A3	A3	A2	A2	A2	A2	A2	A2	A2	A2	A1
Public Service Company of Oklahoma	A1	Aa3	Aa3	Aa3	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2
Southwestern Electric Power Company	Aa3	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2
West Texas Utilities Company	A2	A2	A1	A1	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2	Aa2
SEEBOARD (Eurobond)	Baa1	Baa2	Baa3								

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(Continued from page 2)

Coupon	Type of Debt	Maturity	Moody's Rating
Columbus Southern Power Company			
7.600%	Sr. Sec. Medium-Term Notes	2024	A3
7.450%	Sr. Sec. Medium-Term Notes	2024	A3
6.750%	Sr. Sec. Medium-Term Notes	2004	A3
6.550%	Sr. Sec. Medium-Term Notes	2004	A3
—	Secured MTN Programs	—	A3
—	MTN Program	—	Baa1
—	MTN Program	—	Baa1
6.550%	Medium Term Notes	2008	Baa1
6.510%	Medium Term Notes	2008	Baa1
6.850%	Medium Term Notes	2005	Baa1
—	Issuer Rating	—	Baa1
7.920%	Jr. Sub. Deferrable Interest Debentures	2027	Baa2
8.375%	Jr. Sub. Deferrable Interest Debentures	2025	Baa2
—	7.875% Cum. Pfd. Stk.	—	"baa1"
—	7% Cum. Pfd. Shs.	—	"baa1"
—	Commercial Paper	—	P-2
—	415 Shelf Registration	—	(P)Baa1/Baa2
Indiana Michigan Power Company			
—	Secured MTN Programs	—	Baa1
6.400%	Sr. Sec. Medium-Term Notes	2000	Baa1
—	MTN Program	—	Baa2
—	Issuer Rating	—	Baa2
7.600%	Jr. Sub. Deferrable Interest Debentures	2038	Baa3
000%	Jr. Sub. Deferrable Interest Debentures	2026	Baa3
	6.3% Cum. S.F. Pfd. Stk.	2009	"baa2"
—	6.25% Cum. Pfd. Stk.	2009	"baa2"
—	5.9% Cum. S.F. Pfd. Stk.	2009	"baa2"
—	4.125% Cum. Pfd. Stk.	—	"baa2"
—	4.12% Cum. Pfd. Stk.	—	"baa2"
—	7.08% Cum. Pfd. Stk.	—	"baa2"
—	6.875% Cum. Pfd. Stk.	—	"baa2"
—	Commercial Paper	—	P-2
—	415 Shelf Registration	—	(P)Baa1
—	415 Shelf Registration	—	(P)Baa3
Kentucky Power Company			
7.875%	First Mortgage Bonds	2002	Baa1
—	Secured MTN Programs	—	Baa1
—	MTN Program	—	Baa1
—	MTN Program	—	Baa2
6.910%	Medium Term Notes	2007	Baa2
—	Issuer Rating	—	Baa2
8.720%	Jr. Sub. Deferrable Interest Debentures	—	Baa3
—	Commercial Paper	—	P-2
—	415 Shelf Registration	—	(P)Baa1/Baa2
Ohio Power Company			
9.875%	First Mortgage Bonds	2020	A3
7.750%	First Mortgage Bonds	2002	A3
—	Secured MTN Programs	—	A3
—	MTN Program	—	Baa1
7.375%	Sr. Notes	2038	Baa1
5.730%	Medium Term Notes	2004	Baa1
7.875%	S.F. Debenture	1999	Baa1
—	Issuer Rating	—	Baa1
920%	Jr. Sub. Deferrable Interest Debentures	2027	Baa2
.160%	Jr. Sub. Deferrable Interest Debentures	2025	Baa2
—	5.9% Cum. Pfd. Stk.	2009	"baa1"

Kentucky Power Company

	1997	1996	1995	1994	1993
Coverage Analysis (Excl. AFUDC and Other Allowances)					
Pretax interest coverage	2.19	1.96	2.24	2.33	1.97
SEC interest coverage	2.19	1.96	2.26	2.35	1.98
SEC fixed-charge coverage	2.19	1.96	2.26	2.35	1.98
Funds from oper.%interest exp.	3.15	2.48	2.82	2.88	2.82
Funds from oper.%net CAPEX (%)	82.77	46.47	113.42	75.52	109.69
Funds from oper.%net CAPEX + pref. div.	82.77	46.47	113.42	75.52	109.69
Funds from oper.%total debt (%)	13.64	9.67	13.80	12.41	12.82
Deferred charges as % of common equity	38.95	41.16	42.86	29.55	26.13
Earnings Analysis					
Return on avg.					
Common equity	8.29	7.32	11.72	12.55	9.16
Total assets	2.41	2.11	3.38	3.65	2.80
Total capital	7.31	6.22	7.20	7.20	6.58
AFUDC as % net income	0.00	0.00	1.46	1.91	1.47
Asset Composition					
Total assets	886.7	833.6	772.2	714.3	670.4
As % total assets					
Net utility plant	80.1	79.8	78.9	82.9	83.3
Investments	0.7	0.8	0.8	0.9	1.0
Current assets	7.8	7.4	8.0	7.6	8.1
Deferred charges	11.3	12.0	12.2	8.6	7.6
As % gross electric plant					
Electric plant in prod. (gross)					
Fossil	25.8	26.9	26.2	26.3	26.2
Total electric plant in prod.	25.8	26.9	26.2	26.3	26.2
Other electric plant (gross)					
Transmission	31.6	29.2	29.7	30.3	31.0
Distribution	36.6	36.4	35.7	35.0	34.9
Common plant	2.7	2.2	6.8	6.6	6.8
Construction in process	3.3	5.3	1.7	1.8	1.2
Total other electric plant	74.2	73.1	73.8	73.7	73.8
Construction					
Construction expenditures (excl. AFUDC)	67	76	39	53	35
CWIP % common equity	12.5	19.9	6.6	7.2	4.8
CWIP % gross plant	3.2	5.1	1.7	1.8	1.2
Constr. exp. % prior year cap.	11.0	14.0	7.4	10.7	7.4
Constr. exp. % prior yr. gross plant	7.1	8.6	4.6	6.5	4.5

Kentucky Power Company

	1997	1996	1995	1994	1993
Market Analysis					
Total operating revenue	359.5	323.3	328.1	307.4	294.3
As % total oper. revenue					
Electric	100.0	100.0	100.0	100.0	100.0
As % total electric revenue					
Residential	29.5	32.9	32.8	32.7	33.1
Commercial	16.3	18.1	17.9	18.2	18.3
Industrial	26.3	28.6	29.5	30.2	30.8
Public authority	0.2	0.3	0.3	0.3	0.3
Wholesale	24.8	17.7	18.5	17.5	16.4
Other	2.8	2.5	1.2	1.1	1.1
KWH Sales	12,408	10,108	10,342	9,281	8,916
As % total KWH sales					
Residential	17.7	21.7	21.2	21.8	22.1
Commercial	9.4	11.4	11.0	11.6	11.6
Industrial	25.3	30.4	28.8	30.9	31.3
Other	0.1	0.1	0.1	0.1	0.1
Wholesale	47.5	36.4	38.9	35.6	34.9
Average revenue per KWH (cents)					
Residential	4.82	4.86	4.91	4.97	4.94
Commercial	5.03	5.08	5.16	5.21	5.21
Industrial	3.01	3.00	3.24	3.24	3.25
Wholesale	1.52	1.55	1.50	1.63	1.55

Kentucky Power Co.

Ashland, Kentucky, USA

Ratings

Category	Moody's Rating
Senior Secured MTN	Baa1
Senior Unsecured Debt	Baa2
Issuer Rating	Baa2
Junior Subordinated	Baa3
Senior Secured Shelf	(P)Baa1
Senior Unsecured Shelf	(P)Baa2
Commercial Paper	P-2

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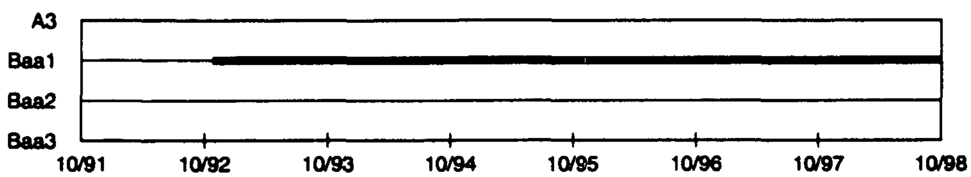
American Electric Power Company, Inc.

Commercial Paper	P-2

Rating History



Operating Statistics

Kentucky Power Company (Statistics in bold type)
Peer Group Median (Statistics in light type)

	[1]1998	1997		1996		1995		1994		[2]5-Yr.Avg.	
Revenue (US$ bil.)	**0.5**	1.1	**0.4**	1.1	**0.3**	1.0	**0.3**	1.0	**0.3**	[3]5.3	**[3]2.8**
Assets (US$ bil.)	**0.9**	2.8	**0.9**	2.7	**0.8**	2.8	**0.8**	2.7	**0.7**	[3]3.1	**[3]7.5**
Com. Equity (US$ bil.)	**0.3**	0.9	**0.3**	0.9	**0.2**	0.9	**0.2**	0.8	**0.2**	[3]2.9	**[3]5.3**
Op. Margin (%)	**10.5**	20.2	**15.8**	20.9	**14.6**	21.9	**16.7**	21.6	**16.2**	21.1	**15.5**
ROA (avg.)(%)	**1.8**	3.6	**2.4**	3.7	**2.1**	3.8	**3.4**	3.5	**3.7**	3.7	**2.9**
ROE (avg.)(%)	**6.2**	11.9	**8.3**	12.1	**7.3**	12.7	**11.7**	11.7	**12.5**	12.1	**9.8**
Pretax Int. Cov. (X)	**1.8**	3.4	**2.2**	3.4	**2.0**	3.4	**2.2**	3.3	**2.3**	3.3	**2.1**
Fxd. Chg. Cov. (X)	**1.8**	2.9	**2.2**	3.0	**2.0**	2.9	**2.3**	2.7	**2.4**	2.8	**2.2**
RCF % TD	**5.2**	15.0	**7.0**	16.1	**3.0**	15.3	**6.6**	14.3	**5.7**	14.8	**5.5**
RCF % Gross CAPEX	**34.7**	123.9	**42.6**	127.6	**14.5**	113.6	**54.0**	89.5	**34.6**	108.8	**38.0**
Total Cap. (US$ bil.)	**0.7**	2.0	**0.7**	2.0	**0.6**	1.9	**0.5**	1.8	**0.5**	[3]3.7	**[3]7.1**
TD % Cap.	**61.1**	50.3	**61.1**	49.9	**60.0**	49.5	**59.2**	50.0	**60.6**	50.0	**60.3**
Pfd. Stk. % Cap.	**0.0**	6.1	**0.0**	5.6	**0.0**	5.7	**0.0**	6.3	**0.0**	6.0	**0.0**
Common % Cap.	**38.9**	44.2	**38.9**	44.7	**40.0**	45.0	**40.8**	44.3	**39.4**	44.5	**39.7**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	105.9	58.7	94.6	89.3
Kwh(mil.)	2197	1166	3142	5894
¢/Kwh	4.8	5.0	3.0	1.5
Industry Avg. (¢/Kwh)	8.9	7.6	5.2	3.4

[1] For the 12 months ended June 30; Balance sheet items are as of June 30. [2] Five year average 1997-1993. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

Kentucky Power Company's (KP) Baa1 senior secured rating reflects the benefits of membership in the American Electric Power (AEP) system and the utility's very competitive generating costs. However, the rating also reflects the company's highly leveraged balance sheet, high percent of industrial and wholesale customers, and generating asset concentration.

The 1,060 mw, two unit, coal-fired Big Sandy plant represents 73% of KP's capacity. This owned capacity is supplemented by a long-term contract to purchase 390 mw from the AEP system's Rockport plant. When fully reflected on the adjusted balance sheet, this substantial off-balance-sheet obligation exacerbates an already weak capital structure.

The company expects that over the next five years, internal cash flow will meet slightly over half of capital expenditures. The company will rely on parent support and the capital markets to meet the rest of its spending needs. Proposed air quality standards may require material AEP system expense in the longer term.

All three Kentucky utilities offer such low rates that the state has felt little pressure for customer choice of supplier. Nonetheless, the legislature is studying competition and may pass legislation in 2000.

Rating Outlook

The stable outlook reflects the intercompany nature of KP's power purchases and AEP's support of this small subsidiary, offsetting the risks of a financial profile that is weaker than the industry norm. We expect the announced merger with Central and South West to have little near-term financial impact.

Moody's Investors Service
Global Credit Research

American Electric Power Company, Inc.

October 1998

Ratings

Category	Moody's Ratings
Appalachian Power Company	A3
Columbus Southern Power Company	A3
Indiana Michigan Power Company	Baa1
Kentucky Power Company	Baa1
Ohio Power Company	A3
American Electric Power Company	
Commercial Paper	P-2

Contacts

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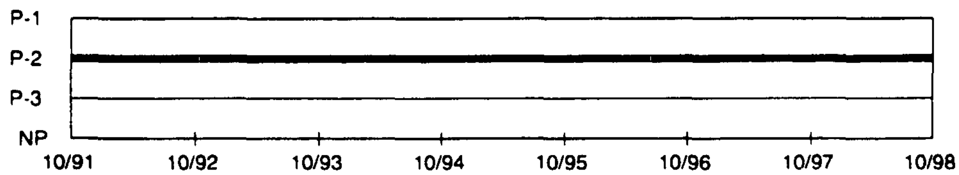
Rating History



Operating Statistics

American Electric Power Company, Inc.

	(1)1998	1997	1996	1995	1994	(2)5-Yr.Avg.
Revenue (US$ bil.)	8.2	6.2	5.8	5.7	5.5	(3)4.1
Assets (US$ bil.)	17.8	16.6	15.9	15.9	15.7	(3)3.2
Com. Equity (US$ bil.)	4.8	4.7	4.5	4.3	4.2	(3)2.0
Op. Margin (%)	15.9	21.5	23.1	22.1	21.2	22.0
ROA (avg.)(%)	3.4	3.1	3.7	3.4	3.2	3.2
ROE (avg.)(%)	12.5	11.1	13.2	12.4	11.9	11.4
Pretax Int. Cov. (X)	3.2	3.4	3.5	3.1	2.9	3.2
Fxd. Chg. Cov. (X)	3.4	3.2	3.0	2.2	2.1	2.5
RCF % TD	12.5	10.7	12.4	13.7	8.0	10.7
RCF % Gross CAPEX	97.6	102.9	134.7	124.6	66.9	101.6
Total Cap. (US$ bil.)	12.4	12.2	11.4	10.5	10.4	(3)2.9
TD % Cap.	60.3	60.2	55.0	52.5	51.6	54.3
Pfd. Stk. % Cap.	12.5	1.4	5.2	6.3	7.9	5.7
Common % Cap.	97.6	38.4	39.7	41.2	40.5	40.1

(1) For the 12 months ended June 30. Balance sheet items are as of June 30. (2) Five year average 1997-1993. (3) Five year compound annual growth rate

Opinion

Rating Rationale

The A3 and Baa1 ratings for American Electric Power's (AEP) utilities are based on the subsidiaries' strong competitive positions and the benefits of association with the system. The ratings also reflect generally modest service territory growth and leverage slightly above industry norms.

AEP's sales are concentrated in the industrial sector, which contributed 46% of 1997 retail sales. AEP's average 1997 retail rate of 4.89 cents per kwh, well below the 7.12 cent national average, should allow the company to compete aggressively and not only maintain, but improve market share as competition approaches. The announced merger with Central and South West should expand and improve the competitiveness of its generating asset portfolio.

The system's 87% coal-fired generating capacity has required substantial Clean Air Act compliance costs, which are being recovered through retail rates and system power pool sales. Further environmental compliance costs, capital expenditures, and non-regulated investments over the next five years will be largely financed with internal cash flow. Proposed new air quality standards may entail material expense longer term.

We expect AEP's non-regulated energy-related ventures to remain modest relative to its size.

Rating Outlook

The rating outlooks for AEP's subsidiaries are stable. We expect the announced merger with Central and South West to have minimal near-term financial impact.

Coupon	Type of Debt	Maturity	Moody's Rating
American Electric Power Company, Inc.			
—	Commercial Paper	—	P-2
American Elect Power Service Co.			
Appalachian Power Company			
8.000%	Sr. Sec. Medium-Term Notes	2025	A3
9.875%	First Mortgage Bonds	2020	A3
6.800%	First Mortgage Bonds	2006	A3
8.000%	Sr. Sec. Medium-Term Notes	2005	A3
7.850%	Sr. Sec. Medium-Term Notes	2004	A3
7.500%	First Mortgage Bonds	2002	A3
7.625%	First Mortgage Bonds	2002	A3
6.375%	First Mortgage Bonds	2001	A3
6.710%	Sr. Sec. Medium-Term Notes	2000	A3
6.350%	Sr. Sec. Medium-Term Notes	2000	A3
7.500%	First Mortgage Bonds	1998	A3
—	Secured MTN Programs	—	A3
7.300%	Sr. Notes	2038	Baa1
7.200%	Sr. Notes	2038	Baa1
—	Issuer Rating	—	Baa1
8.000%	Jr. Sub. Deferrable Interest Debentures	2027	Baa2
8.250%	Jr. Sub. Deferrable Interest Debentures	2026	Baa2
—	5.9% Cum. Pfd. Stk.	2008	"baa1"
—	6.85% Cum. Pfd. Stk.	2004	"baa1"
—	4.5% Cum. Pfd. Stk.	—	"baa1"
—	4.5% Cum. Pfd. Stk.	—	"baa1"
—	7.4% Cum. Pfd. Stk.	—	"baa1"
—	5.92 % Cum. Pfd. Stk.	—	"baa1"
—	Commercial Paper	—	P-2
—	415 Shelf Registration	—	(P)Baa1
—	415 Shelf Registration	—	(P)A3

(Continued on page 36)

Author	Editor	Senior Associate	Senior Production Associate
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Company Fundamentals

BUSINESS FUNDAMENTALS AND COMPETITIVE POSITION

American Electric Power Company (AEP) is one of 12 registered utility holding companies regulated by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935. AEP is a system of five large electric utilities: Appalachian Power Company (AP), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I&M), Kentucky Power Company (KP), and Ohio Power Company (OP); two small, unrated utilities; and one wholesale electric generating company, AEP Generating Company (AEG). AEP is expanding its energy-related investments outside the US and the regulated electric utility sector. To date, these non-regulated investments remain relatively modest, accounting for only 8% of total assets. The largest non-US investment is its 50% interest in Yorkshire Electricity Group, a United Kingdom regional electric distribution and supply company. Table 1 shows the size and scope of the five rated US utilities.

Table 1: 1997 AEP System Overview

	AP	CSP	I&M	KP	OP
Operating Revenues ($000,000)	1,720	1,140	1,392	360	1,966
Sales as % of Retail Sales:					
Residential	37	37	30	34	20
Commercial	21	40	26	18	15
Industrial	40	21	44	48	64
Wholesale as % of Total Sales	42	32	51	48	44
Service Territory	VA, WV	OH	IN, MI	KY	OH
Retail Customers	877,000	621,000	549,000	168,000	679,000
Competitive Position	Above Aver	Average	Average	Above Aver	Above Aver

In December 1997, AEP and Central and South West Corporation (CSW), another registered utility holding company, announced their agreement to merge. The combined companies would do business as "American Electric Power," the brand name AEP adopted in 1996. The companies have identified $2.1 billion in cost savings, net of implementation costs, that would result from the merger over ten years, approximately half each from labor and administration. The new American Electric Power would rank first in the nation in sales, generating capacity, number of customers, and size of currently regulated service territory. That it would rank only fourth in revenues points to the strong competitive position of each company reflected in their low rates. Each of the utilities would retain its separate legal existence and indenture. Shareholders of both companies overwhelmingly approved the merger. The companies anticipate completion of the merger in the first half of 1999.

The five large utilities (the member utilities) benefit from membership in the AEP system power pool through cost sharing and the deferral of construction that would otherwise have been needed. The parent, which has little debt at the holding company level because of strong consolidated cash flow, can also manage the capital structure of a subsidiary to a modest degree through capital contributions and upstreamed dividends. These advantages of financial and operating flexibility currently have a small positive impact on ratings relative to what the ratings of each individual utility on a stand-alone basis might be, particularly for Kentucky Power.

AEP's utilities serve regions that, for the most part, reflect the average growth rate of the nation. As illustrated in Table 2, only Appalachian Power, serving the vibrant western Virginia economy, and Columbus Southern Power, serving the robust Columbus, Ohio, area, expect to see retail sales growth over the next five years that approximates the rate of the last five years. I&M's growth exceeded the national average over that period, however, and the company expects sales to reflect national trends over the next five years. Ohio Power is losing a major industrial customer – aluminum processor Ormet – that will obtain power from third parties, beginning in 1999. OP will very likely offset the loss of slim profits from Ormet with higher profits from sales to the AEP system or external sales.

Table 2: AEP System Retail Sales Growth

	AEP System	AP	CSP	I&M	KP	OP
Five-Year Forecasted Growth	1.3	2.4	2.8	2.0	1.6	-1.0
Five-Year Historical Growth	2.4	2.6	2.9	3.6	2.7	1.6

The System

AEP operates the member utilities' 23,759 megawatts (mw) of generating capacity as a power pool under an economic dispatch system that is 87% coal-fueled (although the system was 92% coal-fired in 1997 due to the Cook nuclear units' outage), 12% nuclear-fueled, and less than 1% hydro-powered. (Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.) A member that sells more power to its retail customers than it has capacity to produce becomes a net purchaser from the pool. Net purchasers (Appalachian Power and Columbus Southern) compensate the sellers (Ohio Power, Indiana Michigan, and, to a small extent, Kentucky Power) for the seller's embedded costs, including capacity, operations, maintenance, and fuel under formulas approved by the SEC. Similar agreements govern sharing of costs and credits for the system's transmission and wholesale power sales. Table 3 illustrates revenue and cost sharing in 1997 from the five members' participation in these agreements. AEP is likely to restructure its cost-sharing agreements with subsidiaries over the next few years to reflect the impact of industry restructuring and the holding company's business strategy.

Table 3: 1997 Shared Costs and Credits ($000's)

Subsidiary	Generation	System Wholesale Power Sales	Power Pool Transmission	Transmission for Non-Affiliated Companies
AP	(237,000)	37,500	(8,400)	18,000
CSP	(138,000)	18,300	(29,900)	10,200
I&M	67,000	42,400	46,100	10,500
KP	20,000	7,700	2,700	3,900
OP	288,000	30,200	(10,500)	27,200

Moody's estimates that only Columbus Southern and Indiana Michigan face potential generation-related stranded costs, which are detailed below. Moody's views these two utilities' stranded costs as manageable and also mitigated by the cost advantages provided by their membership in the AEP system.

THE SUBSIDIARIES

APPALACHIAN POWER COMPANY (AP) – AP contributed 28% of AEP's retail sales in 1997. The company uses its 5,853 mw of mostly coal-fired, highly competitive generating capacity and purchased power from the system pool to serve customers in Virginia and West Virginia. AP's service territory straddles the two states, with 53% of its sales in Virginia and 47% in West Virginia. The economy in the Virginia portion of the service area is expected to be stronger than the West Virginia service area. Industrial customers, which represent 40% of the company's retail sales, include primary metals, chemicals, textiles, paper, and coal mining companies. AP's 1997 industrial rate of 3.55 cents was well below the national average of 4.69 cents.

AP's wholesale sales, which represent 42% of total sales, are to non-affiliated utilities, and to an affiliated non-pool-member, Kingsport Power. Reflecting the impact of the Federal Energy Regulatory Commission's (FERC) open access Order 888, a number of wholesale (municipal utility) customers have given notice of termination. However we anticipate that AP will be able to retain some of this load and that the loss of some of these contracts will have little impact on the company's margins as it is a net purchaser of power from the AEP system. AP's wholesale sales have increased from 27% of total sales to 42% over the past three years.

COLUMBUS SOUTHERN POWER COMPANY (CSP) – CSP contributed 16% of AEP's 1997 retail sales. CSP's sales to the robust Columbus commercial sector account for 40% of its retail sales. (Columbus is the largest city in Ohio and in the AEP service territory.) Industrial sales account for only 21% of retail sales and are spread across a number of industries. The company's industrial rates are about equal to the national average. Regional unemployment is expected to remain below national levels.

CSP's 2,595-mw generating capacity is completely coal-fired. The nuclear-to-coal conversion of the Zimmer plant, which is jointly owned with two unaffiliated utilities, was completed in 1991. While the Zimmer plant is among the most efficient in its region, Moody's estimates that CSP's stranded costs equal 70% of equity (based on 1995 data), primarily attributed to fixed costs associated with the Zimmer investment. Zimmer's costs are reflected in current rates. Moody's expects these stranded costs to be manageable, given their magnitude and the other competitive advantages of CSP belonging to the AEP system.

INDIANA MICHIGAN POWER COMPANY (I&M) – I&M contributed 17.5% of AEP's retail sales in 1997. Indiana accounts for 84% of the utility's retail sales, with the remaining 16% in Michigan. Industrial sales account for 44% of total retail sales, with concentrations in primary metals, electrical machinery, transportation equipment, chemicals, and fabricated metals. I&M's competitive position is average because of its generating cost and rate structure. Its industrial rates equal the regional average.

Off-system sales, which comprised 51% of total sales in 1997, including wholesale sales to the pool, are important to I&M's financial health. I&M and AEP Generating Company each have a 50% interest in both Rockport units, whose total capacity is 2600 mw. (Rockport 2, which went into commercial operation in 1989, is financed through an operating lease.) I&M purchased an additional 455 mw of Rockport capacity from AEG. I&M has sold 250 mw of its total Rockport capacity to an unaffiliated utility under a long-term contract, expiring in 1999. I&M uses the remaining 1,505 mw to meet its retail and power pool demand.

The two Cook nuclear units represent 47% of I&M's 4,434 mw of generating capacity, while nearly all of the balance is coal-fired. The Nuclear Regulatory Commission (NRC) has subjected the Cook units to an extensive review, which commenced in September 1997 during an architectural engineering design inspection, a new type of NRC review. This type of inspection compares the current engineering and the documentation of maintenance for the plant and its support systems with the original design that formed the basis for the operating license approval. The NRC review's main focus in I&M's case was on the cooling system that the NRC inspectors believed might not perform as needed in the event of an accident. The NRC gave Cook a "3" assessment (or "satisfactory" – which tends to mean unsatisfactory for an industry that strives for excellence because of its perceived risks) in the Engineering category in its review that ended March 1998.

The NRC also sent a letter to AEP in July informing them of the NRC's perception of declining performance at Cook. During Cook's lengthy outage, all issues raised by NRC inspectors are being addressed. AEP plans to restart Unit 1 by the end of the first quarter of 1999, a target set in coordination with the NRC inspection team. Unit 2 would restart 90 days later. Moody's believes the Cook units are likely to perform well in succeeding years because of the thoroughness of this review and the company's appointment of a new chief of nuclear operations.

The price spikes the region experienced in June 1998 will not affect replacement power costs because power is obtained from the AEP system under a cost-sharing agreement. Should regulators disallow some portion of the replacement costs, I&M's maximum exposure would be less than $10 million per month, representing the difference between the Cook nuclear units' production costs and the system's production costs.

Based on 1995 data, Moody's estimates I&M's stranded costs at a manageable 41% of equity, largely from investment in and elevated non-fuel operating costs associated with Cook. The two nuclear units have been in operation since the mid-1970s, are more than half way through their operating license (expiring in 2014 and 2017 respectively), and are substantially depreciated. AEP took steps to lower operating costs by consolidating nuclear management at the nuclear plant site.

Storage of waste fuel is a serious issue for the entire nuclear industry. I&M is among the utilities suing the Department of Energy to force it to establish a permanent nuclear waste storage site, as it was supposed to by January 31, 1998, under the Nuclear Waste Policy Act of 1982. Decommissioning and waste disposal costs were recently estimated in a range from $700 million to $1.152 billion in nondiscounted 1997 dollars. I&M is currently collecting in rates at the low end of the range and will continue to seek regulatory approval for adequate recovery of decommissioning costs. It has the capability to store waste nuclear fuel through 2009.

KENTUCKY POWER COMPANY (KP) – KP is the smallest of the AEP member utilities, contributing 7% of retail sales. It has one generating source, the 1,060-mw Big Sandy plant. Although it is a net seller to the power pool, purchased power costs totaled 43% of the utility's operating and maintenance costs in 1997, including purchases from AEP Generating. The utility's competitive position is above both regional and national averages as a result of its low generating costs and reasonable rates. As a result, we expect the company to retain its industrial customer base, which is concentrated in petroleum, primary metals, and chemicals, and which accounts for 48% of total retail sales.

OHIO POWER COMPANY (OP) – OP accounts for 32% of AEP's retail sales, the highest share among the system's member utilities. The utility is also the largest net seller of power to the system power pool. Its 8,464-mw generation capacity serves not only its own retail customers in Ohio, but also wholesale customers, including the AEP power pool, which comprise 44% of total sales. Industrial customers contribute 64% of retail sales, and are heavily concentrated in primary metals, but also include petroleum, rubber, plastics, stone, clay, glass, chemicals, transportation equipment, and electrical machinery manufacturers. Although competition is fierce in the industrial sector, OP's low industrial rates, which average 3.12 cents per kilowatt-hour, are well below the national average of 4.69 cents, and provide a strong competitive edge.

Expiration of two major industrial contracts, Ormet Corporation in 1999 and Ravenswood Aluminum in 2003, which together account for 890 mw of demand, is cause for only modest concern despite OP's low growth rate and high reserve margins. An alternate supplier will replace Ohio Power to serve Ormet in 1999. Both contracts are marginally profitable. Moody's expects retail sales growth within the AEP system, increased system wholesale contracts, and retention of associated transmission revenues to offset the loss of these two large industrial customers.

AEP GENERATING COMPANY – AEP Generating Company, organized in 1982, generates and sells power at wholesale from Rockport Units 1 and 2 (1300 mw each), in which AEP Generating and I&M each have a 50% interest. The units burn clean western coal and enjoy competitive production costs of just over 1.5 cents per kilowatt-hour. Unit 1 is owned, and Unit 2 is leased. KP purchases 30%, or 390 mw, of AEP Generating's share of the power generated by each Rockport unit under a contract expiring at the end of 1999. An unaffiliated utility purchases 70%, or 455 mw, of AEP Generating's share of power available from Rockport Unit 1, through the end of 1999. The remaining portion of AEP Generating's share of Unit 2 is sold to I&M. AEP Corporation (the parent) provides financial support to AEP Generating under a capital funds agreement, ensuring that it will be able to meet any financial obligations.

YORKSHIRE POWER GROUP – Yorkshire Power Group is a British holding company that owns the UK Regional Electricity Company (REC) Yorkshire Electricity Group plc, which is the primary distribution company in England's second largest commercial and industrial center. AEP and New Century Energies each have a 50% interest in Yorkshire Power Group, which acquired the REC in early 1997 for $2.88 billion. AEP's equity contribution was $360 million.

As a REC, Yorkshire is both a "wires" company – distributor of electric power to end-user customers – and supplier arranging for power production and delivery for its customers, similar to power marketers in the US. Detailed discussion of the UK electric sector can be found in *Recycling the RECs*, published by Moody's in May 1998.

OTHER SUBSIDIARIES

AEP Resources – AEP established AEP Resources to invest in non-regulated power projects, both privatizations and greenfields (new construction), around the globe and in foreign utility companies. AEP's 50% interest in Yorkshire Power Group is also held through Resources. AEP Resources' first international power project is a 70% interest in a joint venture to build a $172 million, coal-fired plant in China.

AEP also acquired a 20% interest in Pacific Hydro Ltd., an Australian company that develops and operates hydroelectric plants. A joint venture formed in 1995 between Resources and Cogentrix Energy, called Industrial Energy Partners, is upgrading, replacing, owning, and operating steam and electrical power plants for energy-intensive industrial sites. However, a similarly-focused joint venture with Conoco was terminated in its initial stages in 1998.

AEP Energy Services – AEP's power marketing subsidiary (see Management Strategy section below for further discussion).

AEP Communications – AEP's investment in telecommunications is very modest. It is leasing excess capacity on its own fiber optics network, a strategy of increasing profitability of assets with no additional risk. To add marketing clout and economies of scale, AEP is joining with Allegheny Energy to market their combined fiber optic networks.

Fuel and Environmental Compliance Costs

We believe AEP's generation system will be among the most competitive in the deregulating industry. Declining fuel costs have offset slightly higher non-fuel operating and maintenance costs over the past few years, resulting in total production costs for the system of 1.79 cents per kilowatt-hour in 1997. This production cost advantage allows the company to offer low rates. Competitive fuel costs drive much of this advantage. A comparison of fuel costs for each member utility is presented in Table 4 below.

The difference in fuel costs reflects the distance-sensitive transportation cost of moving coal from mine to generating plant, the ability of a plant to burn coal of varying quality (which is related to its sulfur content), low nuclear fuel costs for I&M, and pricing under long-term contracts, which may still exceed current spot prices. The percentage of coal acquired under long-term contract declined from a peak of 75% in 1995 to 66% in 1997. AEP expects maturing contracts to be replaced with more market-based coal costs, thereby further improving its production cost advantages.

The sulfur content of both CSP and OP reflect use of high sulfur coal from regional mines, including mines in Ohio. Scrubbers on OP's Gavin plant also allow OP to continue to burn Ohio's high-sulfur coal, much of which comes from affiliated mines (see Regulation, Rates and State Restructuring Initiatives below for discussion of regulatory treatment of OP's coal costs from affiliate mines). I&M's Rockport units burn coal from low-sulfur Western mines under contracts that expire in 2004 and 2014.

Table 4: 1997 Fuel Costs and Sulfur Dioxide Content by Member Utility

	AP	CSP	I&M	KP	OP
Cents per MMBtu	156	138	89	111	157
Cents per Kwh	1.50	1.40	0.93	1.03	1.55
Sulfur Dioxide in Lbs/MMBtu	1.3	4.7	1.4	2.1	3.5

As a largely coal-fired system, compliance with environmental standards has entailed substantial expense, particularly for those plants in the Midwest, and they continue to be targets of proposed tighter environmental standards.

The Clean Air Act Amendments of 1990 (CAAA) required reductions in both sulfur dioxide and nitrogen oxides in two phases. Phase I requirements commenced on January 1, 1995, and Phase II's will go into effect on January 1, 2000. AEP developed a systemwide plan to meet the new standards and pursued state regulatory approvals to ensure recovery of costs in affected jurisdictions. Approximately $100 million will be spent in 1998 and 1999 to complete its compliance measures. Installing scrubbers at Ohio Power's Gavin plant at a cost of $610 million reduced AEP's sulfur dioxide emissions 25%, forming a major component of the plan. The CAAA also created annual, tradable emission allowances, set to limit emissions at levels below the system's historic average emission volumes. Allowances which could be sold to other utilities were available to the degree that AEP was successful in reducing actual emissions below the new threshold.

The Environmental Protection Agency proposed even more stringent standards in 1997, especially for nitrogen oxides, which are precursors of ozone formation, and for particulate matter. The Clinton administration, also in 1997, committed the US to reducing greenhouse gas emissions by 7 % from 1990 levels by the years 2009-2012. Northeast states have applied political pressure to reduce emissions from Midwestern generating plants because they believe these plants are major causes of smog and other forms of air pollution.

Although studies show automobile exhaust is a much larger source of air pollution, politics tends to limit curtailing tailpipe emissions. The EPA set forth its final state implementation rule on September 24, 1998, requiring an 85% reduction in nitrogen oxides by 22 states east of the Mississippi by 2003. The affected utilities and their state governors not only view the new standard as severe and costly, but they also fear the tight timetable will affect electrical system reliability, a concern heightened by power interruptions and associated price spikes during the summer of 1998. Governors of 13 affected states and a coalition of utilities promoted a more measured approach, reducing nitrogen oxides by 65% by 2004 or 2005. Their computer modeling shows Northeast cities can remain within EPA's one-hour and eight-hour average smog limits with their proposed level of reduction. Using the electric utilities as a sole means to reduce pollution, without also further addressing the role of auto emissions, will no doubt give electric utilities ammunition in lawsuits likely to follow in the wake of EPA's tougher air pollution standards.

Should the AEP system incur material additional compliance costs, it would be adversely affected to the degree it could not pass increased costs to customers, either through regulation or through market pricing. Because its competitors within the ECAR (East Central Area Reliability Coordination Agreement – a North American Electric Reliability Council region) are also predominately coal-based, as they are near to coal mines and navigable rivers to transport it, they are likely to incur similar costs. For this reason, the governors of these states are leading the effort to soften EPA's proposed air pollution standards, and the outcome may well determine coal's ability to compete with alternative fuels and technologies over the longer term.

Moody's has not factored a potentially significant impact from new and tougher environmental standards into the AEP ratings or outlooks to date as the standards are not yet fixed, the implementation time frame is likely to span a number of years, some of the cost is likely to be absorbed in prices, and AEP generally enjoys competitive cost advantages compared to its peers. We will continue to monitor developments on this issue.

Management Strategy

AEP's strategy for its future is shaped by five priorities:

- Growing the core business and base of existing customers;
- Becoming a top-tier national energy trader and marketer;
- Building a strategic portfolio of global investments through acquisitions and development;
- Expanding products and services for its retail customer base; and
- Adding strategic incremental investments to support both its core and trading businesses.

AEP intends to remain in all three functions of its core businesses: generation, distribution, and transmission. It already has critical mass to provide economies of scale in each sector. Its planned merger with CSW will enhance these economies, expand its customer base, and add diversity to the fuel mix in its portfolio of generating assets. AEP also owns and operates one of the most extensive transmission systems in the US and its investment in transmission capacity, as a percentage of utility plant, is among the highest in the US. FERC's Order 888, issued in April 1996, requires transmission owners to open their transmission systems to all users at prices utilities charge themselves. The intent of the order is to facilitate wholesale electric competition. The utility's own retail load retains usage priority. The order already has created opportunities to make more efficient use of AEP's transmission system and to increase transmission revenues.

MARKET POWER MITIGATION FOR MERGER APPROVAL

The merger partners identified some modest combined ability to exercise market power, but feel they can demonstrate their merger presents no major market power concerns. The detailed calculations are included in their FERC merger filing.

The companies have several measures to mitigate this regulatory concern. First, AEP said it is committed to participate in an independent system operator (ISO), the type of independent entity the FERC prefers for managing the transmission grid. CSW is currently a member of the ERCOT (Electric Reliability Council of Texas) ISO and Southwest Power Pool, which is preparing a FERC application for approval of its ISO. AEP was originally a member of the Midwest ISO, but dropped out when a competing ISO, the "Alliance," was formed. The Midwest ISO offers the broad geographic reach AEP believes is necessary for a successful ISO, but the consensus with regard to revenue sharing formulas was not fair to AEP and its shareholders. AEP participates in both the Alliance and Midwest ISO discussions.

The Public Utility Commission of Ohio (PUCO) opened a process to review the merger and filed as a FERC intervenor in the merger. Moody's expects PUCO's focus to be on AEP's joining the Midwest ISO, the only body of its type PUCO expects to provide the market power mitigation needed in the region, dominated by large utilities. Moody's believes the Midwest ISO is likely to be the dominant ISO in the region. The current membership obtained FERC approvals in September 1998, and other utilities are likely to join because of merger approval pressures. Other market power mitigation steps are also transmission related with an additional commitment to sell 320 mw of energy daily under conditions intended both to mitigate market power and to preserve system reliability.

CSW is also a significant international investor with $2.68 billion invested outside the US. Its largest is SEEBOARD, another leading UK REC that it acquired in 1996 for $2.1 billion. The companies will align their investment strategies after the merger closes. They have significant overlap in the UK, which they could address in a number of ways. The merger's closing and subsequent UK regulatory consideration will no doubt affect strategy relative to this overlap. Moody's views their non-US investments, outside the UK, as otherwise rather complementary as CSW already has a foothold in Latin America, a region not yet pursued by AEP, but within its area of interest.

CONVERGENCE INITIATIVES

AEP announced on September 14, 1998 that it had acquired midstream natural gas assets located in Louisiana from Equitable Resources for $320 million. The transaction is expected to close by year-end 1998, pending regulatory approvals, filings for which have begun. This purchase is intended to complement AEP Energy Services' existing electric and natural gas trading and asset optimization capabilities. AEP Resources is acquiring a 2000-mile intrastate gas pipeline with multiple inter- and intrastate connections and a current average daily throughput of 600 MMcf; four natural gas processing plants that straddle the pipeline, with a fifth under construction; a salt dome gas storage facility, with a second under construction; and more business for its energy trading and marketing office in Houston. This acquisition is a component of its strategy to expand products and services for retail customers along converging energy and utility sectors.

FINANCIAL STRATEGIES

To gain greater financial flexibility to respond to electric industry restructuring, AEP changed its preferred stock charter to eliminate restrictions on the amount of unsecured debt that it could issue. Four of the subsidiary utilities also issued deferrable interest subordinated debentures, which provide some flexibility in their capital structure.

Regulation, Rates, and State Restructuring Initiatives

RATE COMPARISON

AEP and its US utilities' rates are competitive in the region and lower than the national average, as illustrated in the table at right. Appalachian Power, Ohio Power, and Kentucky Power have some of the lowest rates in the region because of their low-cost, efficient coal-fired generating capacity.

Table 6: 1997 Rate Comparisons

Company	Industrial	Commercial	Residential
AP	3.55	5.01	5.62
CSP	4.59	6.27	7.64
I&M	4.41	6.07	6.86
KP	3.01	5.03	4.82
OP	3.12	5.50	6.62
AEP System	3.54	5.66	6.35
ECAR Average	4.38	6.80	7.91
National Average	4.69	7.83	8.94

Source: Regulatory Research Associates and Moody's

MERGER RELATED REGULATORY STRATEGY

The merger partners consulted with state regulators about their plans, but believe they need only state commission approvals for CSW subsidiaries because only those assets will change ownership.

The merger's regulatory plan contains the following benefits:

- Saves the company and ratepayers future costs of $2 billion in non-fuel expenses over 10 years, shared approximately equally between the utilities and customers;
- Saves $98 million in fuel costs over the same period, all savings passed along to ratepayers;
- Increases diversity of customers, generating resources, and service territory, all of which benefits consolidated earnings;
- Enhances customer service;
- Defers and amortizes merger costs over 5 years;
- Supports both electric restructuring and creation of an independent system operator; and
- Freezes base rates at current levels until January 1, 2002.

POWER MARKETING

AEP has been actively involved in wholesale power marketing for a number of years through its own system under profit-sharing arrangements sanctioned by regulators that have minimized the need for a power marketing license. Moody's expects AEP to eventually gain its power marketer's license, which would permit it to trade at market-based rates and retain all profits, as it restructures the many complex aspects of its current business to reflect new market demands and opportunities. The growth in wholesale business over the past three years is illustrated in Table 5 below. I&M's wholesale business, while increasing nine percentage points from 1994, was actually somewhat depressed because of outages at the Cook nuclear facility, which comprised 53% of its total sales in 1996.

AEP intends to capitalize on its people and their expertise to expand trading operations and to include trading in electricity, natural gas, residual fuel, coal, and their associated financial products. AEP Energy Services' staff currently exceeds 100. It is headquartered in Columbus with a satellite office in Houston.

Table 5: Growth in Utility Wholesale Sales

	AP	CSP	I&M	KP	OP	AEP System
1994	27%	32%	42%	36%	31%	19%
1997	42%	16%	51%	48%	44%	31%

The company was well-positioned to capitalize on price spikes experienced in the June 1998 regional wholesale power markets, although the lowest cost power is still dedicated to its retail base. AEP was not affected by credit problems other utilities suffered because of strong risk management practices, which Moody's views as typical for the company, given a somewhat risk-averse senior management team. Senior managers consider their ability to stay informed and involved in risk management a key AEP success factor.

First half 1998 sales have already exceeded 1997's 9.3 megawatt-hours of non-affiliate power sales. Because wholesale markets are so competitive and due to the underlying commodity nature of the product, Moody's expects companies engaging in power marketing to earn only modest margins over time. A trading unit's role, most often, is to enhance profitability of other assets. In fact, AEP views its power marketing arm as a critical link in a chain of assets and core competencies focused on commercial optimization (meaning maximizing consolidated profits) by managing price volatility and geographic and time arbitrage inherent in energy production. The acquisition of the Equitable Resources midstream gas assets in Louisiana is another link in the chain. This is a further reason Moody's also considers the consolidated risk and financial profile of a complex holding company such as AEP when assigning ratings to any of its subsidiaries.

INVESTMENT OUTSIDE THE U.S.

Investment outside the US through its AEP Resources subsidiary is gaining momentum. The SEC approved AEP's request to increase its cap on non-regulated and foreign utility investment to 100% of retained earnings. Its investments outside the US total $1.35 billion to date, and the company intends to invest $300 million per year of new equity in these regions. Moody's regards these investments as modest relative to AEP's size and financial resources. AEP established regional offices in London, Toronto, Sydney, Singapore, and Beijing.

Its largest investment to date is its 50% interest in Yorkshire, which it acquired in 1997 for $1.2 billion, including equity of $360 million. In Australia, AEP acquired a 20% interest in Pacific Hydro for $10 million.

AEP has a foothold in the Chinese power market with 70% interest in a joint venture with Henan Electric Power Development and Nanyang Municipal Financial Development Company. Each Chinese partner contributed 15% to the project, called the Nanyang General Light Electric Company. AEP also refers to it as AEP Pushan Power. The partners are constructing two 125-mw coal-fired units. The first is expected to be operational by year-end 1998, at a total cost of $172 million. A 35% interest in a second power project in Shouyangshan, China, entails a $200 million equity contribution.

A summary of required state filings follows.

Arkansas – The Arkansas Public Service Commission, which has jurisdiction over Southwestern Electric Power (SWEPCO), a CSW subsidiary, approved the merger on August 17, 1998, subject to a number of conditions, none of which appears onerous. The APSC must still review the proposed regulatory plan associated with the merger, and hearings begin in November.

Louisiana – The merger plan was filed with the Louisiana Public Service Commission on May 15, 1998, and the companies anticipate an order in April 1999. The Louisiana plan also requests approval to share off-system sales profits above recent levels equally with ratepayers, and authorizes SWEPCO to increase regulatory asset amortization and distribution depreciation expense by approximately $26 million during the 10-year period.

Oklahoma – AEP and CSW filed their merger plan with the Oklahoma Corporation Commission on August 14, 1998.

Texas – The companies filed their merger case with the Public Utility Commission of Texas on April 30, 1998, offering benefits and sharing mechanisms like those offered in the other states. The merger filing was sensitive to issues of particular interest to this activist commission. The Texas commission had already ordered rate reductions for Central Power and Light (CPL) in a 1997 rate case that served as a signpost for where the commission intends to take interim rate proceedings in preparation for competitive markets. Full restructuring legislation is not anticipated in Texas in the 1999 session, but interim restructuring measures may pass. The companies hope the merger case will focus on the merger and not on industry restructuring, and, given the rather punitive order against CPL last year, Moody's believes the commission is likely to not bring the bigger issues of restructuring into its considerations of the merger.

FERC – The Federal Energy Regulatory Commission merger approval case was filed on April 30, 1998. The elements are described in the Management Strategy section above.

SEC – Both companies are registered holding companies, so their merger filing will need to address the many PUHCA requirements within the context of their corporate strategies. They anticipate submitting the merger approval request to the SEC within the fourth quarter of 1998.

NRC – CPL also filed a license transfer application with the Nuclear Regulatory Commission on June 19. It owns a 25% share in the two-unit South Texas Project nuclear plant.

The UK – American Electric Power and CSW anticipate that regulators in the UK will let the US merger close, then deal with the implications. Regulation itself is under review in the country and may change before the merger closes.

STATE REGULATORY PROCEEDINGS AND RESTRUCTURING INITIATIVES

APPALACHIAN POWER COMPANY: The Virginia State Corporation Commission increased AP's rates $30.5 million effective November 11, 1997. AP is collecting the increased revenues subject to refund as settlement deliberations continue. The utility is still operating under an 11.4% ROE from a 1992 rate case. The Virginia rate hike will help finance the needed Wyoming to Cloverdale high-voltage transmission line (which still needs certification for construction from the Virginia commission), that will improve service reliability not only for AP's customers, but also for the regional grid, according to the North American Electric Reliability Council. This and one other major transmission line are estimated to cost $268 million and to be in service by the end of 2002.

Virginia passed initial restructuring legislation in March 1998, setting in motion the process to create an Independent System Operator and Power Exchange by January 1, 2001. Retail markets would not open to full choice of generation supplier until January 1, 2004. A legislative committee is working on a second restructuring bill for next year, providing the details of retail electric sector reform.

A settlement agreement in West Virginia resulted in a $28 million fuel cost recovery reduction effective November 1996 with an associated $5 million base rate reduction. Base rates in West Virginia are subsequently frozen until January 1, 2000, and fuel over- or under recoveries will be deferred over the same period for later consideration. Over-recoveries exceeding $10 million will be shared equally between ratepayers and AP. On May 28, 1998, the Public Service Commission of West Virginia certified the construction of a 32-mile segment that passes through the state of the 132-mile Wyoming-Cloverdale high-voltage transmission line.

West Virginians enjoy some of the lowest rates in the country, limiting pressure to restructure its electric sector. In fact, a rather unique debate over stranded costs may slow West Virginia restructuring initiatives. The Public Service Commission may not meet its deadline to deliver a restructuring plan to the legislature by the end of 1998 because of the delay. Consumer advocates raised concerns that potential stranded benefits may not be shared by ratepayers. The PSC requested informational filings including details on potentially stranded costs from each of the state's utilities as part of development of the restructuring plan.

COLUMBUS SOUTHERN POWER COMPANY: No CSP rate cases have been filed or are intended. CSP still operates under a 12.46% ROE from a 1992 order, which ultimately, after court appeals, resulted in a $124.6 million rate increase to recover allowed Zimmer plant investment.

An Ohio legislative task force, established in early 1997 to develop recommendations on restructuring the state's electric sector, made little progress by the end of the year. Its report was delayed into 1998 and even then it did not reflect a consensus of the committee. Restructuring faces hurdles in Ohio that it doesn't in other states, such as a tax policy that relies heavily on utilities to raise state and local revenues, and vastly different stranded cost exposures among the state's utilities. Prospects for a bill improved when the utilities (perhaps observing what happened in Pennsylvania, which shared the latter challenge) developed their own consensus plan for restructuring the state's electric sector. The consensus plan was presented to the legislature in September 1998, and a committee representing interested parties was established to examine the proposal's merits. No legislation is likely until after the 1998 elections, and probably not until well into 1999.

INDIANA MICHIGAN POWER COMPANY: I&M has required no recent base rate proceedings and operates under an ROE of 12.0% from a November 1993 order and a 13.0% ROE from a February 1991 Michigan order.

I&M anticipates that restructuring legislation will be introduced once again in Indiana in 1999. Investor-owned utilities in the state are working together to develop a consensus plan, which will improve chances of legislation passing. If no bill passes in that session, the 2000 session is a short one, leaving 2001 as the next opportunity to deal with the issue. The governor has played no active role in this process. Moody's observes that governors have been actively involved in those states that have moved forward on electrical deregulation legislation.

In fact, Michigan is one of the states where restructuring is moving forward even though formal legislation has not been introduced. The Michigan Public Service Commission has provided very visible leadership, but legislation is needed to provide stronger legal footing for the restructuring process for all affected utilities and for securitization of stranded costs. Introduction of legislation is unlikely before the November 1998 election. However, 60% of the House will leave office by year's end as term limits take effect this year, and that provides strong incentives for restructuring legislation to be passed in the lame duck session rather than having to educate a new group of legislators on this complex subject.

The approach utilized by the MPSC for the two largest Michigan utilities provides a solid framework for a transition to competition in Moody's view. In orders to date for the largest utilities the commission has supported adequate stranded cost recovery, an annual true-up mechanism that balances the interests of ratepayers and investors, and a reasonably rapid transition to full choice for customers.

KENTUCKY POWER COMPANY: The Kentucky Public Service Commission issued a May 1997 order allowing KP to establish a $1.2 million (annualized) surcharge to recover environmental compliance costs. Although the rate relief officially began July 7, 1997, the first year was offset by a $1.9 million rate reduction to account for gains on the sale of emission allowances. The company appealed the order. Kentucky Power's most recent ROE was 11.5%.

The Kentucky legislature established a task force to examine restructuring, and a report outlining its recommendations is due November 1999. A bill may be introduced in the year 2000 with passage of legislation the following year that will allow for a moderate transition to full choice of generation supplier no earlier than 2005. The state enjoys generally low electric rates, minimizing pressure for restructuring.

OHIO POWER COMPANY: No base rate cases have been required since a March 1995 order when PUCO awarded a $66 million increase to recover the costs of installing scrubbers on OP's Gavin plant. No ROE was mentioned in the settlement.

Ohio Power's coal costs for the Gavin plant, which are primarily for coal from affiliate mines located in Ohio, are being recovered through two channels. The largest portion, the Ohio retail jurisdictional portion, is recovered through a fixed fuel component in rates that began at $1.575 per MMBtu (i.e. heat content) in December 1994 with quarterly escalators. (AEP's system coal costs were $1.4023, and OP's averaged $1.5166 per MMBtu.) OP is permitted to recover its investment in affiliated Ohio coal mines to the degree its actual coal costs are less than the fixed fuel factor. It recovers the wholesale jurisdictional portion from the system's net purchasers of power through the cost sharing agreement approved by the SEC. AEP expects to recover the Ohio jurisdictional portion of its investment in these mines through this mechanism and estimates OP's non-Ohio-jurisdictional exposure to mine closing costs at $102 million at the end of 1997. Although Moody's stranded cost model shows no potential stranded costs for OP, the mines, which would not have been captured in the model, may be a source of potential stranded costs in an eventual rate case.

A court decision opined that the SEC rather than FERC had jurisdiction over affiliate coal costs. At issue were these affiliate coal costs. The FERC wanted to disallow the over-market portion whereas the SEC approved the affiliate costs. The landmark decision was called the Ohio Power decision and served to clarify jurisdictional reach. As part of the FERC merger filing, AEP and CSW agree to waive the Ohio Power defense for FERC ratemaking purposes regarding all affiliate contracts entered into after the merger's close – except these coal contracts, and for these, too, beginning in 2002, by which date OP expects to have closed all three of the mines.

(See Columbus Southern directly above for discussion of Ohio restructuring initiatives.)

Risks/Weaknesses

- The company's leverage is higher than the industry average, although this is offset by the good-to-excellent competitive positions of its member utilities.
- Regulatory support in recent years has been weak, causing the utilities to rely on cost -cutting to improve financial ratios as business risks increase.
- The AEP system, for the most part, expects only modest economic growth, following national trends.

Opportunities/Strengths

- Low-cost, coal-fired generating capacity provides a competitive advantage.
- Completed construction cycles allow lower capital expenditures, improved cash flow, and reduced regulatory risk.
- Geographic reach and a balance between competitive initiatives and a conservative investment strategy position AEP to benefit from coming deregulation.

Financial Analysis

Merger savings are rather modest at $1.032 billion given the size of the companies and the 10-year period used to measure the savings. As the two companies are not contiguous, fewer opportunities for elimination of redundancies are available. The companies propose sharing the savings resulting from the merger equally between ratepayers and shareholders.

AEP's Yorkshire investment in the UK faced a higher than anticipated, politically motivated, one-time windfall profits tax similar to all REC owners. AEP's share of the tax equaled $109 million in US dollars, after tax, and caused a 13% decline in consolidated net income in 1997 to $511 million. Without the tax, net income would have been up 6%. The cash flow impact of the tax is split between 1998 and 1999.

AEP's strong cash flow and its tendency to leverage its utilities where they do not receive regulatory support has permitted it to finance much of its non-regulated investment internally. The payout ratio averaged 83% over the past three years. The internal sources of equity and retention of cash at the parent level are illustrated in Table 7.

Under current projections, AEP will not need new capacity until after 2002 as the system's reserve margin was 17% in 1997 at the summer peak, and a 455 mw contract to sell electricity to Virginia Electric Power expires in 1999, freeing more generating capacity. The company's estimate of future reserve margin averages 18% for the 1998 through 2001 period. Some utility observers may regard this reserve margin as a strategic asset to support its expansion of its power marketing operations. Profits from third party sales are shared with ratepayers under formulas established or reaffirmed in their most recent rate cases.

Table 7: Parent's Retained Cash Flow

Dividends Received from Subsidiaries:	1997	1996	1995
AP	74,436	58,300	76,836
CSP	78,684	75,876	56,900
I&M	131,260	112,508	110,852
KP	6,760	-5,736	18,100
OP	199,333	142,856	139,428
Kingsport Power	255	1,088	-152
Wheeling Power	1,315	2,376	2,316
Total Dividends Received	*492,043*	*387,268*	*404,280*
DRIP* Proceeds	77,000	65,000	49,000
Cash Flow at Parent	*569,043*	*452,268*	*453,280*
Dividends Paid to Shareholders	453,453	449,353	445,831
Retained Cash Flow	*115,590*	*2,915*	*7,449*

* *Dividend reinvestment program*

AEP forecasts capital expenditures of an average of $740 million during the next five years compared to $762 million in 1997 and $578 million in 1996. Construction expenditures include the replacement of steam generators at Cook Unit 1 at a cost of $175 million. Costs for remaining CAAA compliance measures for the system are estimated at $100 million.

AEP's ability to finance non-regulated investment internally to date plus its tendency to use leverage at its utilities that receive little regulatory support is illustrated in Table 8's financial ratio comparisons. The ratios are for 1997 only, and therefore do not speak to trends. The ratios are also unadjusted, whereas I&M and OP, through their leases, and KP through its purchased power commitments actually have larger fixed obligation burdens than shown here, reducing their coverage ratios to ones more in line with their respective rating categories.

Table 8: Financial Profiles – 1997 (Unadjusted; Including Subordinated Debt)

	AEP	AP	CSP	I&M	KP	OP
P/T Interest Coverage	3.18	2.55	3.35	4.31	2.16	4.99
FFO* Interest Coverage	4.01	2.99	3.59	5.22	2.66	5.50
Total Debt to Capital	55.2%	59.1%	57.2%	50.5%	59.5%	45.6%

* *Funds From Operations*

AEP began its Year 2000 (Y2K) computer remediation efforts in 1996 and expects to complete testing for compliance in 1999. IBM is assisting it in these efforts, which are expected to cost a total of between $56 and $68 million. The scope of the efforts includes internal systems and those of suppliers. As a nuclear plant operator, I&M is required to certify Cook's Y2K readiness by July 1, 1999.

Individual utility capital expenditure plans follow.

APPALACHIAN POWER COMPANY: Besides its estimated $268 million planned expenditures on high-voltage transmission capacity, AP also plans to add three combustion turbines by the end of 2003 at a cost of $162 million. Total construction expenditures are expected to average $256 million over the next five years, slightly more than the $218 million spent in 1997. AP anticipates meeting over half its capital expenditures through internal cash.

COLUMBUS SOUTHERN POWER COMPANY: CSP anticipates meeting all its capital expenditures through internal cash flow. It forecasts construction expenditures averaging $120 million over the next five years, compared to the $108 million spent in 1997.

INDIANA MICHIGAN POWER COMPANY: I&M's capital expenditures are expected to average $133 million over the next five years, similar to the $123 million spent in 1997. However, the timing of these expenditures will be weighted more towards the earlier years because of the Cook initiatives. It expects to easily meet capital expenditures through internal cash.

KENTUCKY POWER COMPANY: KP expects its capital expenditures to average $43 million per year over the next five years, substantially lower than 1997's $67 million. Construction expenditures on transmission lines have been elevated and will remain higher than normal over the next two years, after which KP will primarily upgrade and maintain its distribution system. Only half of these expenditures will be financed through its own cash flow, with the balance from parent contributions and external financing.

OHIO POWER COMPANY: OP expects its average annual capital expenditures to remain at the same level as 1997's, $173 million. Internal cash should amply cover these expenditures.

Credit Analysis—Update

Kentucky Power Company

A subsidiary of American Electric Power Company. Inc

Brian M Youngberg. CFA (312) 368-3332
John W O'Connor (312) 368-2059

September 17 1998

Ratings:	**Security Class**	**DCR**	**Latest Change**	**Prior**	**Moody's/S&P**
	First Mortgage Bonds	**BBB+**	05/98	NR	Baa1/A
	Sr Unsecured Notes	**BBB**	05/98	NR	Baa1/BBB
	Jr Sub Deferred Debentures	**BBB-**	05/98	NR	NR/NR
	Commercial Paper	**D-2**	05/98	NR	NR/NR
Rating Watch:		**No**			*/No

Rating Rationale

- Kentucky Power Company's (KPCo) credit quality is stable as it benefits from a competitive position based on its low busbar and marginal generation costs, competitive rate structures and limited stranded cost exposure
- As part of American Electric Power's (AEP) integrated system of seven operating electric utilities. KPCo benefits from being able to operate with a slightly negative reserve margin due to its active purchasing of AEP system power from the AEP Power Pool. KPCo purchases 390Mw from affiliate AEP Generating Company's Rockport Generating Plant under an agreement through 2004. The Power Pool allows KPCo to postpone new plant construction
- KPCo's interest and debt coverages are weak for its rating category due to negative free cash flow and lack of regulatory support. The low fundamentals are offset by KPCo's cost and rate structures. Unadjusted interest coverages are expected to remain stable for the foreseeable future. Adjusted figures increasingly do not reflect actual credit quality due to inclusion of AEP's allocated wholesale trading and marketing procurement costs in purchased power expense
- Regulatory support has historically been relatively low in a state with multiple low-cost electric utilities. KPCo's last filed a rate case in 1984 and has no plans to file. A historically strict regulatory environment has negatively impacted KPCo's financial fundamentals. Kentucky regulators and legislators are not actively pursuing electric industry restructuring
- Free cash flow will continue to be negative. AEP is expected to continue to contribute common equity periodically to supplement new debt issues in covering a modest capital expenditure plan and maintain the current capital structure
- KPCo benefits from strong nongeneration asset coverage relative to secured debt.
- KPCo's service territory is predominantly rural and is experiencing an improving, but still relatively sluggish, economy Principal industry concentrations include petroleum refining, chemicals and coal, which together represent approximately two-thirds of KPCo's industrial load.
- KPCo shares some of the Federal Clean Air Act compliance costs of its AEP affiliates through its Power Pool purchases
- KPCo's credit quality is not expected to be impacted by the proposed merger of AEP and Central and South West Corp

Liquidity/Debt Structure

KPCo shares short-term lines of credit with other AEP companies. Short-term borrowings are limited by regulation to $150MM and are used for working capital requirements. Internal cash flow covers just under one-half of capital expenditures, thus requiring KPCo to periodically issue debt and receive equity contributions from AEP to maintain the current capital structure

Recent Developments

The Environmental Protection Agency has proposed plans that may force Midwest coal-fired generators such as KPCo (and AEP as a whole) to significantly reduce their nitrogen oxide emissions. If enacted as proposed, AEP estimates its corporatewide potential costs at $1 6B in a worst-case scenario. Such restrictions are still being studied and would not be enacted in the near term. Actual costs and KPCo's ability to pass such costs on to customers cannot yet be determined.

Rating Issues

Historical lack of rate support resulting in stable, but below-average financial fundamentals including interest coverages and leverage. Negative free cash requiring periodic AEP common equity contributions and debt issuances. Uncertain long-term impact from potential increased pollution regulation.

Fundamentals

Contribution

	Rev.	Op. Inc.-%	Jurisdiction-% Revenue
Elec	100	100	KY-74 FERC-26

	95-97 Ann. Growth-%			**Revenue Derivations-%**			
	Rev.	Sales	Cust.	Res.	Comm.	Ind.	Whl.
Elec	1 3	2 9	1 0	30	17	27	26

Elec. Capacity-Mw				**Elec. Energy Mix-%**	
Owned	Pur.	Peak	Rsrv.	C	PP
1 060	390	1 711	na	60	40
23.759*	0*	19 557*	22%*		

Avg. Elec. Unit Prices—Retail-(Cents/kwh)

Res.		Comm.		Ind.	
Co.	Rgn.	Co.	Rgn.	Co.	Rgn.
4.8	7 7	5 0	6 6	3 0	4 3

Avg. Elec. Unit Cost - Generation-Cents/kwh)		**1998-2002**	
Co.	Rgn	Constr ($)	2'0MM
1 8	2 8	Capital	Stdr
		Int Cash/Cons	Incr

* AEP Power Pool

Attachment
Page 140 of 141
KPSC Case No. 99-149
KESI's (2nd Set)
Supplemental Request for Information
Item No. 17

Kentucky Power Company

($ in Millions Except As Noted)

Financial Ratios	12 Months Ended 6/98	6/97	1997	1996	1995	1994	1993
EBIT/Interest (X)	1 8	2.2	2.2	2 0	2.2	2 4	1 9
EBITDA/Interest (X)	2.8	3 3	3.2	3.0	3 3	3 5	3 0
EBITDA/Interest-Adj. (X)	1 7	2.3	2.2	2.1	2.3	2.3	2 0
Internal Cash to Construction (%)	12.4	31 4	21 8	27.4	48.1	46.9	40 5
Deferred Debits/Com. Eq. (%)	56.9	38.7	39.0	41.2	42.9	29 5	26 1
Return on Common Equity (%)	6.2	8.4	8.3	7 3	11 7	12 6	9 2
Common Dividend Payout Ratio (%)	173.1	126 8	129.0	143.0	91 2	84 7	125.8
Average Interest Cost	7 2	6 9	6.8	7 0	7 6	6 9	7 4
Capitalization							
Long-term Debt (%)	49.7	49.1	54 5	50 4	48 7	49 0	52 1
Short-term Debt (%)	10.9	10 1	6.2	9.1	10 5	10 7	7 9
Total Debt (%)	60.6	59 2	60.6	59 5	59 2	59 7	60 0
Debt Adj. for Purch. Power (%)	77 0	68.9	70.8	69 4	69 2	70 5	71 2
EBITDA/Debt (%)	19.5	21 5	21.0	20.2	24 3	23 3	21 4
EBITDA/Debt-Adj. (%)	14 4	17 5	17 0	16 6	19 2	18 2	16 9
Preferred Stock (%)	0 0	0 0	0 0	0 0	0.0	0 0	0 0
Common Equity (%)	39 4	40 8	39 4	40.5	40 8	40 3	40 0
Growth in Invested Capital (%)	7 1	11 8	8.7	11.3	4 5	6 4	3 4
Fundamental Financial Information							
Revenues	482	323	360	323	328	307	294
Revenues Less Energy	168	161	169	159	159	151	137
EBITDA	78	79	83	72	78	72	62
Depreciation & Amortization	27	26	26	25	24	23	22
EBIT	51	53	57	47	53	49	40
AFC & Other Non-Cash	0	0	0	0	0	0	0
Interest Charges	28	24	26	24	24	21	21
Preferred Dividends	0	0	0	0	0	0	0
Balance for Common	16	20	21	17	25	25	18
Total Invested Capital	661	618	654	601	540	517	486
Total Debt	401	366	396	358	320	309	292
Total Preferred	0	0	0	0	0	0	0
Retained Earnings	71	83	78	84	91	89	85
Cash Flow							
Cash Flow From Operations	35	52	41	45	42	46	37
Dividends (Pref. and Common)	28	26	27	24	23	21	23
Internal Cash	7	27	15	21	19	25	14
Construction Excluding AFC	57	85	67	76	39	53	35
Other Investment Cash Flow (Net)	0	0	0	0	0	-1	-1
Redemptions	2	0	0	75	0	0	86
Total Capital Requirements	59	85	67	150	39	52	120
Total Financing	52	57	52	130	21	27	105
Total Purchased Power Expense	235	97	114	96	88	95	95
Other Data							
KWH Sales Total (MM)	NA	NA	12,408	10,108	10,342	9,281	8,916
KWH Sales Retail (MM)	NA	NA	6,514	6,428	6,317	5,977	5,802
% Growth in Retail Sales	NA	NA	1 3	1 8	5 7	3.0	1 9
Net Utility Plant in Service	694	613	679	617	594	577	549
CWIP	22	68	32	48	15	15	9
Nonutility Property & Investments	6	7	7	6	6	6	6
Ratings History (1st Mtg Bonds)							
DCR	BBB+	NA	NA	NA	NA	NA	NA
Moody's	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
Standard & Poor's	A	A	A	A	A	A	A

Debt Maturities	
1998*	0
1999	60
2000	25
2001	60
2002	25

* Remaining

Financing Alternatives	Used	Unused
Principal Short Term Facilities ($MM)		
Committed Lines/Commercial Paper	43	107
Securities Registered for Sale ($MM)		
Debt (Secured)		100
Debt (Unsecured)		52

KENTUCKY POWER COMPANY

d/b/a

AMERICAN ELECTRIC POWER

PSC CASE NO. 99-149

RESPONSE TO DATA REQUEST (2ND SET)

ATTORNEY GENERAL FOR THE

COMMONWEALTH OF KENTUCKY

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)))))	CASE NO. 99-149

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

Filed May 17, 1999

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Joint Applicants' Response to Requests for Information of the Attorney General, Office for Rate Intervention (Second Set) was served by overnight delivery, on this 14th day of May, 1999 upon:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

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2110 CBLD Center
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Capital Link Consultants
315 High Street
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Mark R. Overstreet

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of The Joint Application Of

KENTUCK POWER COMPANY, AMERICAN	)	
ELECTRIC POWER COMPANY, INC. AND	)	CASE NO. 99-149
CENTRAL AND SOUTH WEST CORPORATION	)	
REGARDING A PROPOSED MERGER	)	

SECOND REQUESTS FOR INFORMATION
PROPOUNDED BY THE ATTORNEY GENERAL

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information Kentucky Power Company D/B/A American Electric Power to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

CERTIFICATE OF SERVICE AND OF FILING

I hereby ccrtify that this the 11th day of May, 1999, I have filed the original and ten copies of the foregoing with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Ky., 40601, and that I have served the partics by mailing a copy of same, postage prepaid, to:

Errol K Wagner
Director of Regulatory Affairs
American Electric Power
1701 Central Avenue
P O Box 1428
Ashland KY 41105 1428

William H Jones
Vanantwerp Monge Jones & Edwards
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and

SECOND DATA REQUESTS OF THE ATTORNEY GENERAL

AG-2-1 What is the date of the last general rate case of Indiana Michigan Power Company (I&M)?

AG-2-2 Were all or some portion of I&M's individual and/or all or some portion of the allocated portions of AEP's system-wide compliance costs for Phase I and Phase II compliance with the Clean Air Act as Amended included in the last I&M rate case? If the answer is that some portion of those expenses were not included in I&M's last rate case, please quantify the portion of expenses, as related to the company's total expenses of achieving compliance, that were not included in the last rate proceeding.

AG-2-3 Are the costs enumerated in AG-2-2 being recovered as a result of some proceeding outside a general rate case? If so, please name the proceeding, and please state the portion of the total costs recovered in that proceeding.

AG-2-4 Will I&M's individual or the allocated share of AEP system-wide costs of any added NOx compliance measures taken to comply with federal measures now under consideration that may arise during the period of the rate freezes operating in Indiana be recovered from I&M ratepayers during the period covered by the rate freezes? If the answer is yes, please describe the mechanism or means by which that recovery will occur.

AG-2-5 Does the company know or has the company projected the impact the failure, if any, to recover the costs set out in AG-2-2 and AG-2-4 during the periods of the rate freezes will have on I&M's financial rating? If so, what is that known or projected impact?

AG-2-6 Has the announcement of the rate freezes affected the financial rating of I&M? If so, what has the impact been?

AG-2-7 What are the dates of the last general rate cases of CSW's Central Power and Light Company (CPL), West Texas Utilities Company (WTU) and Southwestern Electric Power Company (SWEPCO)?

AG-2-8 Were some or all of CPL's, WTU's and/or SWEPCO's individual and/or some or all allocated portions of CSW's system-wide compliance costs for Phase I and Phase II compliance with the Clean Air Act as Amended included in the last rate cases of each of those companies? If the answer is that some portion of those expenses were not included in any of the companies' last rate cases, please quantify that portion of expenses, as related to each company's total expenses of achieving compliance, that were not included in the last rate proceeding.

AG-2-9 Are the costs enumerated in AG-2-8 being recovered as a result of some proceeding outside a general rate case? If so, please name the proceeding, and please state the portion of the total costs recovered in that proceeding.

AG-2-10 Will CPL's, WTU's and/or SWEPCO's individual or the allocated share of CSW system-wide costs of any added NOx compliance measures taken to comply with federal measures now under consideration that may arise during the period of the rate freezes operating in Texas be recovered from CPL, WTU and/or SWEPCO's ratepayers during the period covered by those rate freezes? If the answer is yes, please describe the mechanism or means by which that recovery will occur.

AG-2-11 Do the companies know or have the companies projected the impact the failure, if any, to recover the costs set out in AG-2-8 and AG-2-10 during the periods of the rate freezes will have on the financial ratings of CPL, WTU and SWEPCO? If so, what is that known or projected impact for each company?

AG-2-12 Has Kentucky Power Company (KPC) had a change in its financial rating as a result of its earnings for the past 3 years? If so, when did that change occur and what was the change?

AG-2-13 Has KPC had a change in its financial rating as a result of the Commission's decision in its environmental surcharge case, Administrative Action Number 96-489?

AG-2-14 Has KPC had a change in its financial rating as a result of the Franklin Circuit Court's decisions in the appeals of the Commission's Order in Administrative Action No. 96-489?

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

What is the date of the last general rate case of Indiana Michigan Power Company (I&M)?

RESPONSE:

See the Company's response to Kentucky Electric Steel Inc.'s Supplemental Request for Information, Question No. KESI-15.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Were all or some portion of I&M's individual and/or all or some portion of the allocated portions of AEP's system-wide compliance costs for Phase I and Phase II compliance with the Clean Air Act as Amended included in the last I&M rate case? If the answer is that some portion of those expenses were not included in I&M's last rate case, please quantify the portion of expenses, as related to the company's total expenses of achieving compliance, that were not included in the last rate proceeding.

RESPONSE:

I&M's last general rate case was based on a 1991 test year. Phase 1 of the Clean Air Act as Amended became effective in 1995. No costs associated with either Phase 1 or Phase 2 compliance would have been included in I&M's last rate case, and therefore a quantification is not available.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Are the costs enumerated in AG-2-2 being recovered as a result of some proceeding outside a general rate case? If so, please name the proceeding, and please state the portion of the total costs recovered in that proceeding.

RESPONSE:

Compliance costs associated with the FERC approved AEP System Interim Allowance Agreement are included as part of I&M's Michigan St. Joseph Rate Area PSCR Clause. Compliance costs included in the 1995 and 1996 PSCR cases were approved. Orders regarding 1997 and 1998 have not been issued. A quantification of the portion of the total compliance costs recovered in the PSCR proceedings is not available.

WITNESS: RICHARD E. MUNCZINSKI

4

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Will I&M's individual or the allocated share of AEP system-wide costs of any added NOx compliance measures taken to comply with federal measures now under consideration that may arise during the period of the rate freezes operating in Indiana be recovered from I&M ratepayers during the period covered by the rate freezes? If the answer is yes, please describe the mechanism or means by which that recovery will occur.

RESPONSE:

During the period of the Indiana agreement, absent a force majeure, AEP shall not file a petition, which, if approved, would have the effect, either directly or indirectly, of authorizing a general increase in Indiana's basic rates and charges.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Does the company know or has the company projected the impact the failure, if any, to recover the costs set out in AG-2-2 and AG-2-4 during the periods of the rate freezes will have on I&M's financial rating? If so, what is that known or projected impact?

RESPONSE:

The Company rejects the premise of the question; that is, that the costs set out in AG-2-2 and AG-2-4 will not be recovered. However, the Company does not know the impact such "failure" will have on I&M's financial rating. Such ratings are made by independent agencies.

WITNESS: RICHARD E. MUNCZINSKI

9

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Has the announcement of the rate freezes affected the financial rating of I&M? If so, what has the impact been?

RESPONSE:

There has been no change in the rating of I&M to date. The "rate freeze" was only one component of the settlement agreement and financial rating would reflect consideration of all factors regarding the company and not any one component.

WITNESS: RICHARD E. MUNCZINSKI

7

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

What are the dates of the last general rate cases of CSW's Central Power and Light Company (CPL), West Texas Utilities Company (WTU) and Southwestern Electric Power Company (SWEPCO)?

RESPONSE:

See the Company's response to Kentucky Electric Steel Inc.'s Supplemental Request for Information, Question No. KESI-15.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Were some or all of CPL's, WTU's and/or SWEPCO's individual and/or some or all allocated portions of CSW's system-wide compliance costs for Phase I and Phase II compliance with the Clean Air Act as Amended included in the last rate cases of each of those companies? If the answer is that some portion of those expenses were not included in any of the companies' last rate cases, please quantify that portion of expenses, as related to each company's total expenses of achieving compliance, that were not included in the last rate proceeding.

RESPONSE:

The CSW Companies have not incurred any compliance costs associated with Phase I and Phase II of the Clean Air Act. Therefore, the last rate cases of the CSW Companies did not include any Phase I or Phase II costs.

WITNESS: RICHARD E. MUNCZINSKI

KPSC Case No. 99-149
AG's (2nd Set)
Supplemental Request for Information
Item No. 9
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

SUPPLEMENTAL REQUEST:

Are the costs enumerated in AG-2-8 being recovered as a result of some proceeding outside a general rate case? If so, please name the proceeding, and please state the portion of the total costs recovered in that proceeding.

RESPONSE:

The CSW Companies have not incurred any compliance costs associated with Phase I and Phase II of the Clean Air Act. Therefore, the CSW Companies have not initiated a non-rate case proceeding.

WITNESS: RICHARD E. MUNCZINSKI

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Will CPL's, WTU's and/or SWEPCO's individual or the allocated share of CSW system-wide costs of any added Nox compliance measures taken to comply with federal measures now under consideration that may arise during the period of the rate freezes operating in Texas be recovered from CPL, WTU and/or SWEPCO's ratepayers during the period covered by those rate freezes? If the answer is yes, please describe the mechanism or means by which that recovery will occur.

RESPONSE:

The projected NOx compliance measure costs are projected to be minimal (less than $1 million). Therefore, the CSW Companies do not anticipate initiating a proceeding to recover these NOx compliance measure costs during the rate freeze periods.

WITNESS: RICHARD E. MUNCZINSKI

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KPSC Case No. 99-149
AG's (2nd Set)
Supplemental Request for Information
Item No. 11
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Do the companies know or have the companies projected the impact the failure, if any, to recover the costs set out in AG-2-8 and AG-2-10 during the periods of the rate freezes will have on the financial ratings of CPL, WTU and SWEPCO? If so, what is that known or projected impact for each company?

RESPONSE:

The Company rejects the premise of the question; that the costs set out in AG 2-8 and AG 2-10 will not be recovered. The CSW Companies do not know and have not projected the impact of the failure, if any, to recover the costs set out in AG 2-8 and AG 2-10 will have on its financial ratings. Such ratings are made by independent agencies.

WITNESS: RICHARD E. MUNCZINSKI

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Has Kentucky Power Company (KPC) had a change in its financial rating as a result of its earnings for the past 3 years? If so, when did that change occur and what was the change?

RESPONSE:

The rating agencies used multiple criteria in making their determinations. There has been no change in Kentucky Power's credit ratings in the past three years except S&P changed the rating on senior secured debt from BBB+ to A in 1997.

WITNESS: RICHARD E. MUNCZINSKI

KPSC Case No. 99-149
AG's (2nd Set)
Supplemental Request for Information
Item No. 13
Sheet 1 of 1

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Has KPC had a change in its financial rating as a result of the Commission's decision in its environmental surcharge case, Administrative Action Number 96-489?

RESPONSE:

The rating agencies used multiple criteria in making their determinations. There has been no change in Kentucky Power's credit ratings in the past three years except S&P changed the rating on senior secured debt from BBB+ to A in 1997.

WITNESS: RICHARD E. MUNCZINSKI

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Has KPC had a change in its financial rating as a result of the Franklin Circuit Court's decisions in the appeals of the Commission's Order in Administrative Action Number 96-489?

RESPONSE:

The credit agencies used multiple criteria in making their determinations. There has been no change in Kentucky Power's credit ratings in the past three years except S&P changed the rating on senior secured debt from BBB+ to A in 1997.

WITNESS: RICHARD E. MUNCZINSKI