CASE NUMBER:

99-149

KENTUCKY POWER COMPANY
d/b/a

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

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

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

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

RESPONSE:

Attached please find a copy of the 1996 and 1997 FERC Form 1 for Kentucky Power Company. Kentucky Power Company's 1998 FERC Form 1 is not yet available. It will be provided as soon as it is available.

WITNESS: RICHARD E. MUNCZINSKI

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

Form Approved
OMB No. 1902-0021
(Expires 7/31/98)

Attachment 1
Page 1 of 397
KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 3

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, 1996

RESPONDENT'S STATEMENT

The undersigned has examined the reports and that to the best of his knowledge and behalf all information contained in the paper copy of this report is the same information contained in the electronic media filing report.

Dated: 1/5/98

Name: G. R. KNORR
Title: Assistant Controller

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 stating 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 certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 41.10-41.12 for specific qualifications.)

III. W : and Where to Submit (Continued)

(Continued

Schedules	Referenc 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 NE., Washington, DC 20426 (Attention: Mr. Michael Miller, 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 shall not include `municipalities' as hereinafter defined;

(4) `person' means an individual or a corporation;

(5) `licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) `municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, 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 may prescribe the manner and form in which such reports shall be made, amd 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, amend, 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	
...ct legal Name of Respondent ..TUCKY POWER COMPANY	02 Year of Report Dec. 31, 1996
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) 1701 CENTRAL AVENUE, ASHLAND, KENTUCKY 41105	
05 Name of Contact Person G. C. DEAN	06 Title of Contact Person MGR. - FINANCIAL REPORTING
07 Address of Contact Person (Street, City, State, Zip Code) AEPSC, 1 RIVERSIDE PLAZA, COLUMBUS, OHIO 43215	

08 Telephone of Contact Person, including Area Code	09 This Report is	10 Date of Report (Mo, Da, Yr)
(614) 223-2780	(1) An Original (2) x A Resubmission	12/31/96

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	03 Signature	04 Date Signed (Mo, Da, Yr)
G. R. KNORR		
02 Title ASSISTANT CONTROLLER		01/05/98

Title 18, U.S.C. 1001, makes it a crime for any person 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.

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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	12/31/96	Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility)

…ter in column (d) 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".

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101	Ed. 12-87	
Control Over Respondent	102	Ed. 12-96	
Corporations Controlled by Respondent	103	Ed. 12-96	NA
Officers	104	Ed. 12-96	
Directors	105	Ed. 12-95	
Security Holders and Voting Powers	106 - 107	Ed. 12-96	
Important Changes During the Year	108 - 109	Ed. 12-96	
Comparative Balance Sheet	110 - 113	Ed. 12-94	
Statement of Income for the Year	114 - 117	Ed. 12-96	
Statement of Retained Earnings for the Year	118 - 119	Ed. 12-96	
Statement of Cash Flows	120 - 121	Ed. 12-96	
Notes to Financial Statements	122 - 123	Ed. 12-96	
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200 - 201	Ed. 12-89	
Nuclear Fuel Materials	202 - 203	Ed. 12-89	NA
…tric Plant in Service	204 - 207	Rev. 12-95	
…ic Plant Leased to Others	213	Rev. 12-95	NA
…ic Plant Held for Future Use	214	Ed. 12-89	
Construction Work in Progress -- Electric	216	Ed. 12-87	
Construction Overheads -- Electric	217	Ed. 12-89	
General Description of Construction Overhead Procedure	218	Ed. 12-88	
Accumulated Provision for Depreciation of Electric Utility Plant.	219	Ed. 12-88	
Nonutility Property	221	Rev. 12-95	
Investment in Subsidiary Companies	224 - 225	Ed. 12-89	NA
Materials and Supplies	227	Ed. 12-96	
Allowances	228 - 229	Ed. 12-95	
Extraordinary Property Losses	230	Ed. 12-93	NA
Unrecovered Plant and Regulatory Study Costs	230	Ed. 12-93	NA
Other Regulatory Assets	232	Ed. 12-95	
Miscellaneous Deferred Debits	233	Ed. 12-94	
Accumulated Deferred Income Taxes (Account 190)	234	Ed. 12-88	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Capital Stock	250 - 251	Ed. 12-91	
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252	Rev. 12-95	NA
Other Paid-in Capital	253	Ed. 12-87	
Discount on Capital Stock	254	Ed. 12-87	NA
…al Stock Expense	254	Ed. 12-86	NA
…Term Debt	256 - 257	Ed. 12-96	

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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) 12/31/96	Year of Report Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	Ed. 12-96	
Taxes Accrued, Prepaid and Charged During Year	262 - 263	Ed. 12-96	
Accumulated Deferred Investment Tax Credits	266 - 267	Ed. 12-89	
Other Deferred Credits	269	Ed. 12-88	
Accumulated Deferred Income Taxes -- Accelerated Amortization Property	272 - 273	Ed. 12-96	NA
Accumulated Deferred Income Taxes -- Other Property	274 - 275	Ed. 12-96	
Accumulated Deferred Income Taxes -- Other	276 - 277	Ed. 12-96	
Other Regulatory Liabilities	278	Ed. 12-94	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	300 - 301	Ed. 12-96	
Sales of Electricity by Rate Schedules	304	Ed. 12-95	
Sales of Resale	310 - 311	Ed. 12-88	
Electric Operation and Maintenance Expenses	320 - 323	Ed. 12-95	
Number of Electric Department Employees	323	Ed. 12-93	
Purchased Power	326 - 327	Ed. 12-95	
[illegible]smission of Electricity for Others	328 - 330	Ed. 12-90	
[illegible]ssion of Electricity by Others	332	Ed. 12-90	
M[illegible]laneous General Expenses -- Electric	335	Ed. 12-94	
Depreciation and Amortization of Electric Plant	336 - 337	Ed. 12-95	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	Ed. 12-87	
COMMON SECTION			
Regulatory Commission Expenses	350 - 351	Ed. 12-96	
Research, Development and Demonstration Activities	352 - 353	Ed. 12-87	
Distribution of Salaries and Wages	354 - 355	Ed. 12-88	
Common Utility Plant and Expenses	356	Ed. 12-87	NA
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401	Rev. 12-90	
Monthly Peaks and Output	401	Rev. 12-90	
Steam-Electric Generating Plant Statistics (Large Plants)	402 - 403	Rev. 12-95	
Hydroelectric Generating Plant Statistics (large Plants)	406 - 407	Ed. 12-89	NA
Pumped Storage Generating Plant Statistics (Large Plants)	408 - 409	Ed. 12-88	NA
Generating Plant Statistics (Small Plants)	410 - 411	Ed. 12-87	NA

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LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Line Statistics	422 - 423	Ed. 12-87	
Transmission Lines Added During Year	424 - 425	Ed. 12-86	
Substations	426 - 427	Ed. 12-96	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental Protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	NA
Stockholders' Reports Check appropriate box:			
[X] Four copies will be submitted.			
[ ] No annual report to stockholders is prepared.			

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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) 12/31/96	Dec. 31, 1996

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 the office where any other corporate books are kept, if different from that where the general corporate books are kept.

G. R. Knorr, Assistant Controller
AEPSC, 1 Riverside Plaza
Columbus, Ohio 43215

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

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 of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - Kentucky

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the the principal accountant for your previous year's certified financial statements?

Yes...Enter the date when such independent accountant was initially engaged:

X No

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Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CONTROL OVER RESPONDENT

. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of 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 beneficiaries 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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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	12/31/96	Dec. 31, 1996

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 policymaking 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 copy only.		
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< Page 104 Line 1 Column a >

Executive Compensation

The following table shows for 1996 the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by regulations of the Securities and Exchange Commission) of the Company at December 31, 1996.

Summary Compensation Table

	Annual Compensation		Long-Term Compen-sation Payouts	All Other Compen sation
Name and Principal Position	Salary ($)	Bonus ($)(1)	LTIP Payouts ($)(1)	($)(2)
E. Linn Draper, Jr. Chairman of the board and chief executive officer of the Company; chairman, president and chief executive officer of AEP Co., Inc. and Service Corporation; chairman and chief executive officer of other subsidiaries	720,000	281,664	675,903	31,990
Peter J. DeMaria Vice president, controller and director of the Company; executive vice president administration and chief accounting officer and director of the Service Corporation; vice president, controller and director of other subsidiaries	360,000	140,832	290,825	21,190
G.P. Maloney Vice president and director of the Company; executive vice president chief financial officer and director of the Service Corporation; vice president and director of other subsidiaries	360,000	140,832	286,288	21,190
William J. Lhota President, chief operating officer and director of the Company; executive vice president and director of the Service Corporation; president, chief operating officer and director of other subsidiaries	320,000	125,184	263,114	19,690
James J. Markowsky Vice president and director of the Company; executive vice president power generation and director of the Service Corporation; vice president and				

Page 104 Footnote.1

director of other subsidiaries

303,000	118,534	254,535	19,480

(1) Amounts in the "Bonus" column reflect payments under the Management Incentive Compensation Plan for performance measured for the year ended December 31, 1996. Payments are made in March of the subsequent year. Amounts for 1996 are estimates but should not change significantly.

Amounts in the "Long-Term Compensation" column reflect performance share unit targets earned under the Performance Share Incentive Plan three-year performance period ending December 31, 1996.

(2) For 1996, includes (i) employer matching contributions under the AEP System Employees Savings Plan: Dr. Draper, $3,600; Mr. DeMaria, $3,175; Mr. Maloney, $4,500; Mr. Lhota, $4,500; and Dr. Markowsky, $3,235; (ii) employer matching contributions under the AEP System Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan: Dr. Draper, $18,000; Mr. DeMaria, $7,625; Mr. Maloney, $6,300; Mr. Lhota, $4,800; and Dr. Markowsky, $5,855; and (iii) subsidiary companies director fees: $10,390 for each of the named executive officers.

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) 12/31/96	Dec. 31, 1996

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.

Name (and Title) of Director (a)	Principal Business Address (b)
E. Linn Draper, Jr., Chairman of the Board and Chief Executive Officer	Columbus, Ohio
W. J. Lhota, President and Chief Operating Officer (A)	Columbus, Ohio
C. R. Boyle, III, President and Chief Operating Officer (B)	Ashland, Kentucky
P. J. DeMaria, Vice President and Controller	Columbus, Ohio
G. P. Maloney, Vice President	Columbus, Ohio
James J. Markowsky, Vice President	Columbus, Ohio
R. A. Petti (B)	Columbus, Ohio
J. H. Vipperman (A)	Columbus, Ohio

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(A) Elected January 1, 1996.
(B) Resigned January 1, 1996.
Company does not have an Executive Committee.

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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 and give other important particulars (details) concerning the voting rights of such security. State whether voting rights 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 for 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 rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any 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 general public where the options, warrants, or rights were issued on a prorata basis.

1. Give 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 or the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting:
book does not close.	Total: 1,009,000 By proxy: 1,009,000	May 13, 1996 Columbus, Ohio

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): December 31, 1996 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1,009,000	1,009,000	0	0
5	TOTAL number of security holders	1	1	0	0
6	TOTAL votes of Security holders listed below	1,009,000	1,009,000	0	0
7	American Electric Power Company, Inc.				
8	1 Riverside Plaza				
9	Columbus, Ohio 43215	1,009,000	1,009,000	0	0
10					
11					
12					
13					
14					
15					
16	Item 2. None				
17	Item 3. None				
18	Item 4. None				

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IMPORTANT CHANGES DURING THE YEAR

e particulars (details) concerning the matters indicated oelow. 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 therefor 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 e transactions, name of the Commission auth ing ne transaction, and reference to Commission autho ation.

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, ssigned or surrendered: Give effective dates, lengths of s, names of parties, rents, and other conditions. State 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

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IMPORTANT CHANGES DURING THE YEAR (Continued)

Kentucky Power Company

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1. None

2. None

3. None

4. None

5. None

6. Kentucky Public Service Commission Case No. CF-KP-32101:

$25,000,000 6.42% Term Loan due April 1, 1999

$25,000,000 6.57% Term Loan due April 1, 2000

$25,000,000 7.445% Term Loan due September 20, 2002

SEC File No. 70-8693 under the Public Utility Holding Company Act of 1935. Short-term borrowing authority not to exceed $150,000,000 for the period January 1, 1996 through December 31, 2000.

7. None

8. Salary and wage increases include a 3.0% general increase for physical employees. Also included is a 4.0% base merit budget increase for exempt employees; a 3.8% base merit budget increase for the nonexempt clerical employees; and a 4.0% base merit budget increase for nonexempt technical employees.

9. On April 12, 1993, Kentucky Power Company (KEPCo) and other AEP System companies filed a transmission tariff with the Federal Energy Regulatory Commission (FERC) under which these AEP System companies would provide limited transmission service to certain companies. The tariff covered the terms and conditions of the service, as well as the price which the companies pay for transmission services, regardless of the source of electric power generation. On September 3, 1993, the FERC issued an order accepting the transmission service tariff for filing, with the tariff becoming effective on September 7, 1993, subject to refund.

On April 24, 1996, the FERC issued orders 888 and 889. These orders, which resulted from the FERC's March 29, 1995 Notice of Proposed Rulemaking ("Mega-NOPR"), 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

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IMPORTANT CHANGES DURING THE YEAR (Continued)

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 FERC'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 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 the FERC.

KEPCo and Appalachian Power Company (APCo) have announced an improvement plan to be implemented during a four-year period (1996-1999) to reinforce their 138,000-volt transmission system. Included in this plan is a new transmission line to link KEPCo's Big Sandy Plant to communities in eastern Kentucky. APCo's and KEPCo's estimated project costs are [illegible]115,000 and $84,184,000, respectively. The Kentucky Public Service Commission (Kentucky PSC) approved the project in its order dated June 11, 1996. Construction commenced in late 1996.

The Acid Rain Program (Title IV) of the Clean Air Act Amendments of 1990 (CAAA) contain provisions governing nitrogen oxides (NOx) emissions. In April 1995, the United States Environmental Protection Agency (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 in the Federal Register for wet bottom wall-fired boilers, cyclone boilers, units applying cell burner technology and all other types of boilers. These emission limitations are to be achieved by January 1, 2000. A petition for review of the regulations was filed by a number of utilities, including KEPCo, in the U.S. Court of Appeals for the District of Columbia Circuit on December 26, 1996.

The CAAA contains additional provisions, other than the Acid Rain Program, which could require reductions in emissions of nitrogen oxides from fossil fuel-fired power plants. Title I, dealing generally with attainment of federally set National Ambient Air Quality Standards, establishes a tiered system for classifying degrees of non-attainment with the air quality standard for ozone. Depending upon the severity of non-attainment within a given non-attainment area, reductions in nitrogen oxides emissions from fossil fuel-fired power plants may be required as part of a state's plan for achieving attainment with the ozone air quality

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IMPORTANT CHANGES DURING THE YEAR (Continued)

standard. While ozone non-attainment is largely restricted to urban areas, AEP System generating units could be determined to be affecting ozone concentrations and may therefore, eventually be required to reduce nitrogen oxides emissions pursuant to Title I.

In addition, certain environmental organizations and states have taken the position that nitrogen oxides emissions from the midwest must be reduced in order to achieve the air quality standard for ozone in the northeast as well as the Lake Michigan and Atlanta, Georgia areas. All AEP coal-fired plants are potentially subject to the imposition of additional emission controls resulting from these initiatives. The Environmental Council of States formed the Ozone Transport Assessment Group (OTAG) in early 1995 to develop estimates of levels of reduction in volatile organic compound and/or nitrogen oxides emissions required for significant reductions in ozone concentrations in the eastern United States. OTAG, consisting of the environmental commissioners and air directors of 37 eastern states, Federal EPA and representatives from environmental and industry groups, is currently scheduled to complete modeling and technical work by the spring of 1997 with evaluation of technical findings and recommendations on regional emission controls to be submitted to Federal EPA in the summer of 1997. Federal EPA published a notice of intent in the January 10, 1997 Federal Register proposing the specification of ranges or amounts of nitrogen oxides and volatile organic compounds reductions required by states to reduce downwind concentrations of ozone. Federal EPA will direct states to revise their state implementation plans (SIPs) to provide for specified emission reductions within a set time period. Federal EPA's proposal for reductions of nitrogen oxides and volatile organic compounds is scheduled to be issued in March 1997 and final SIP calls requiring revisions in state plans will be issued in the summer of 1997. The cost of meeting NOx emissions reduction requirements which might be imposed to achieve the ozone ambient air quality standard cannot be precisely predicted but could be substantial.

On June 27, 1985, Federal EPA issued stack height regulations pursuant to an order of the United States Court of Appeals for the District of Columbia Circuit. These regulations were appealed by a number of states, environmental groups and investor-owned electric utilities (including KEPCo), along with three electric utility trade associations. Various petitions for reconsideration filed with and denied by Federal EPA were also appealed. This litigation was consolidated into a single case. On January 22, 1988, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision in part upholding the June 1985 stack height rules and remanding certain of the June 1985 rules to Federal EPA for further consideration. While it is not possible to state with particularity the ultimate impact of the final rules on KEPCo operations, at present it appears that the final rules will not result in substantially more stringent emission standards at KEPCo's plant.

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IMPORTANT CHANGES DURING THE YEAR (Continued)

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 CAAA. 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 KEPCo, have filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the regulations.

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. 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. KEPCo is presently identified as a potentially responsible party for clean-up at one federal remediation site. KEPCo's share of clean-up costs, however, is not expected to be significant.

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9. None

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

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)	-	$666,559	$584,778
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
57	Other Regulatory Assets (182.3)	232	101,046,982	105,697,228
58	Prelim. Survey and Investigation Charges (Electric) (183)	-	4,324,480	4,324,480
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	-		
60	Clearing Accounts (184)	-	271,791	216,722
61	Temporary Facilities (185)	-	35,419	35,419
62	Miscellaneous Deferred Debits (186)	233	6,855,032	6,199,157
63	Def. Losses from Disposition of Utility Plt. (187)	-		
64	Research, Devel. and Demonstration Expend. (188)	352-353		
65	Unamortized Loss on Reacquired Debt (189)	-	709,417	875,419
66	Accumulated Deferred Income Taxes (190)	234	29,652,850	30,918,588
67	Unrecovered Purchased Gas Costs (191)	-		
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		$143,562,530	$148,851,791
69	TOTAL Assets and other Debits (Enter Total of lines 10,11,12, 22,52,and 68)		$821,219,708	$882,294,057

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COMPARATIVE BALANCE SHEET (LIABILITES AND OTHER CREDITS)

	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		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252		
7	Other Paid-in Capital (208-211)	253	78,750,000	108,750,000
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	91,381,397	84,090,394
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250-251		
14	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 13)	-	$220,581,397	$243,290,394
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	294,436,000	220,000,000
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257		
19	Other Long-Term Debt (224)	256-257		75,000,000
20	Unamortized Premium on Long-Term Debt (225)	-	35,784	0
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	1,946,596	1,801,804
22	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-	$292,525,188	$293,198,196
	OTHER NONCURRENT LIABILITIES			
	Obligations Under Capital Leases-Noncurrent (227)	-	7,063,891	9,833,194
	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-	2,499,780	2,790,258
27	Accumulated Provision for Pensions and Benefits (228.3)	-	121,517	110,882
28	Accumulated Miscellaneous Operating Provisions (228.4)	-	5,345,621	6,732,542
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		$15,030,809	$19,466,876
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-	27,050,000	51,675,000
33	Accounts Payable (232)	-	11,608,140	16,272,200
34	Notes Payable to Associated Companies (233)	-		
35	Account Payable to Associated Companies (234)	-	10,158,114	14,784,916
36	Customer Deposits (235)	-	3,704,018	3,408,527
37	Taxes Accrued (236)	262-263	7,972,012	5,064,182
38	Interest Accrued (237)	-	5,852,518	5,216,744
39	Dividends Declared (238)	-		
40	Matured Long-Term Debt (239)	-		
41	Matured Interests (240)	-		
42	Tax Collections Payable (241)	-	1,215,989	1,415,195
43	Miscellaneous Current and Accrued Liabilities (242)		9,712,466	4,766,731
44	Obligations Under Capital Leases-Current (243)		2,354,908	3,016,654
45	TOTAL Current and Accrued Liabilities(Enter Total of lines 32 thru 44)		$79,628,165	$105,620,149

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

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)		$212,619	$260,560
48	Accumulated Deferred Investment Tax Credits (255)	266-267	18,396,915	17,007,124
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	31,018	55,777
51	Other Regulatory Liabilities (254)	278	20,155,911	18,938,562
52	Unamortized Gain on Reacquired Debt (257)	269		
53	Accumulated Deferred Income Taxes (281-283)	272-277	174,657,686	184,456,419
54	TOTAL Deferred Credits (Enter Total of Lines 47 thru 53)		$213,454,149	$220,718,442
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
	TOTAL Liabilities and Other Credits (Enter Total of Lines 14, 22, 30, 45 and 54)		$821,219,708	$882,294

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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 duing 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	$323,320,876	$328,143,879
3	Operating Expenses			
4	Operation Expenses (401)	320-323	212,733,727	214,061,460
5	Maintenance Expenses (402)	320-323	32,793,010	27,876,611
6	Depreciation Expense (403)	336-337	25,084,571	24,395,836
7	Amort. & Depl. of Utility Plant (404-405)	336-337	0	0
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
	Regulatory Debits (407.3)			
	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	7,080,115	6,972,744
14	Income Taxes - Federal (409.1)	262-263	5,118,476	7,935,335
15	- Other (409.1)	262-263	709,738	1,458,393
16	Provision for Deferred Income Taxes (410.1)	234,272-277	13,395,997	10,976,607
17	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277	11,539,377	13,349,182
18	Investment Tax Credit Adj. - Net (411.4)	266	(1,232,340)	(1,243,524)
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)		2,204,396	
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of Lines 4 thru 22)		$281,978,137	$279,122,896
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		$41,342,739	$49,020,983

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STATEMENT OF INCOME FOR THE YEAR (Continued)

resul· ; from settlement of any rate proceeding affecting reven.. received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance she·t, income, and expense accounts.

f 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		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
[redacted]						1
$323,320,876	$328,143,879					2
[redacted]						3
212,733,727	214,061,460					4
32,793,010	27,876,611					5
25,084,571	24,395,836					6
0	0					7
38,616	38,616					8
						9
						10
						1
						1.
7,080,115	6,972,744					13
5,118,476	7,935,335					14
709,738	1,458,393					15
13,395,997	10,976,607					16
11,539,377	13,349,182					17
(1,232,340)	(1,243,524)					18
						19
						20
2,204,396						21
						22
$281,978,137	$279,122,896	0	0	0	0	23
$41,342,739	$49,020,983	0	0	0	0	24

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STATEMENT OF INCOME FOR THE YEAR (Continued)

Line	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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21						
22						

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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)	--	$41,342,739	$49,020,983
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)			
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			
31	Revenues From Nonutility Operations (417)			
32	(Less) Expenses of Nonutility Operations (417.1)			
33	Nonoperating Rental Income (418)		58,559	65,412
34	Equity in Earnings of Subsidiary Companies (418.1)	119		
35	Interest and Dividend Income (419)		25,177	53,195
36	Allowance for Other Funds Used During Construction (419.1)			
37	Miscellaneous Nonoperating Income (421)		65,953	39,883
38	Gain on Disposition of Property (421.1)		493	14,854
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$150,182	$173,344
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		83,643	0
42	Miscellaneous Amortization (425)	340		0
43	Miscellaneous Income Deductions (426.1-426.5)	340	1,354,665	578,233
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$1,438,308	$578,233
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	41,246	34,862
47	Income Taxes - Federal (409.2)	262-263	(473,600)	(162,277
48	Income Taxes - Other (409.2)	262-263	(111,634)	(38,2
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	249,397	137,2
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)	234,272-277	242,346	144,803
51	Investment Tax Credit Adj. - Net (411.5)		(157,451)	(234,921)
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		($694,388)	($408,097)
54	Net Other Income and Deductions (Enter Total of lines 39, 44, 53)		($593,738)	$3,208
55	Interest Charges			
56	Interest on Long-Term Debt (427)		21,359,411	21,512,087
57	Amort. of Debt Disc. and Expense (428)		224,328	215,847
58	Amortization of Loss on Reacquired Debt (428.1)		120,104	57,516
59	(Less) Amort. of Premium on Debt - Credit (429)		1,344	17,637
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340	3,060,480	2,495,843
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		986,963	367,996
64	Net Interest Charges (Enter Total of lines 56 thru 63)		$23,776,016	$23,895,660
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$16,972,985	$25,128,531
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)		0	0
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)		0	0
72	Net Income (Enter Total of lines 65 and 71)		$16,972,985	$25,128,531

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STATEMENT OF RETAINED EARNINGS FOR THE YEAR

Report all changes in appropriated retained earnings, appropriated retained earnings, and unappropriated undistributed subsidiary earnings for the 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.

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Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance - Beginning of Year		$91,381,397
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
	TOTAL Credits to Retained Earnings (Acc. 439) (Total of lines 4 thru 8)		
	Debit:		
1	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acc. 439) (Total of lines 10 thru 14)		
16	Balance Transferred from Income (Account 433 less Account 418.1)	117	16,972,985
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acc. 436) (Total of lines 18 thru 21)		
23	Dividends Declared - Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
9	TOTAL Dividends Declared - Preferred Stock (Acct. 437) (Total of lines 24 thru 28)		
0	Dividends Declared - Common Stock (Account 438)		
1	Common Stock		(24,263,988)
2			
3			
4			
	TOTAL Dividends Declared - Common Stock (Acct. 438) (Total of lines 31 thru 35)		($24,263,988)
7	nsfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
8	ance - End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36, and 37)		$84,090,394

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STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE,FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL ·opriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter total of lines 45 and 46)	0
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter total of lines 38 and 47)	$84,090,394
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)	
49	Balance - Beginning of Year (Debit or Credit)	0
	E ty in Earnings for Year (Credit) (Account 418.1)	
	( ) Dividends Received (Debit)	
5	Other Changes (Explain)	
53	Balance - End of Year (Total of Lines 49 Thru 52)	0

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STATEMENT OF CASH FLOWS

the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in pages 122-123. Information about noncash investing and financing activities should be provided on pages 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 pages 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 (Line 72(c) on page 117)	$16,972,985
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	25,196,277
5	Amortization of (Specify)	
6	Debt Expense Discount and Premium	222,984
7	Gain or Loss on Reacquired Debt	120,104
8	Deferred Income Taxes (Net)	1,863,671
9	Investment Tax Credit Adjustment (Net)	(1,389,791)
10	Net (Increase) Decrease in Receivables	1,596,042
11	Net (Increase) Decrease in Inventory	(6,412,086)
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,366,984
14	Net (Increase) Decrease in Other Regulatory Assets	444,822
15	Net Increase (Decrease) in Other Regulatory Liabilities	354,599
16	(Less) Allowance for Other Funds Used During Construction	0
	(Less) Undistributed Earnings from Subsidiary Companies	
	Other:Net (Increase) in Accrued Utility Revenues	5,325,102
	Other Operating Items (Net)	(628,926)
20		
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	$45,032,767
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (Including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(75,815,486)
27	Gross Additions to Nuclear Fuel	
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	0
30	(Less) Allowance for Other Funds Used During Construction	0
31	Other:	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	($75,815,486)
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
38	Proceeds from sale of property-milton, pole sales	250,000
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	
	Purchase of Investment Securities (a)	
4	oceeds from Sales of Investment Securities (a)	

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STATEMENT OF CASH FLOWS (Continued)

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)	($75,565,486)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
	Long - Term Debt (b)	74,985,000
	Preferred Stock	
6	Common Stock	
64	Other: Capital Contributions	30,000,000
65		
66	Net Increase in Short - Term Debt (c)	24,625,000
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	$129,610,000
71		
72	Payments for Retirement of:	
73	Long - term Debt (b)	(74,737,500)
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	(24,263,988)
82	Net Cash provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	$30,608,512
	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57, and 83)	$75,793
	Cash and Cash Equivalents at Beginning of Year	1,030,599
8		
90	Cash and Cash Equivalents at End of Year	1,106,392

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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.

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SEE PAGE 123 FOR REQUIRED INFORMATION

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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, transmission and distribution of electric power in eastern Kentucky and does business as American Electric Power (AEP). The Company provides electric power to 167,000 retail customers in its service territory. Wholesale electric power is supplied to neighboring utility systems, power marketers and the AEP System Power Pool. As a member of the AEP System Power Pool (Power Pool) and a signatory company to the AEP Transmission Equalization Agreement, KPCo's 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 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.

NOTES TO FINANCIAL STATEMENTS (Continued)

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) No. 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.

Use of Estimates

The preparation of these financial statements requires in certain instances the use of management's 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 from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. 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 recovered with regulator approval over the service life of utility plant through depreciation and represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1996 and 1995 were not significant.

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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 as follows:

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

Expenditures to remove retired plant are 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

Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues.

Fuel Cost

Changes in retail jurisdictional fuel costs are deferred until reflected in billings to customers in later months through a fuel adjustment mechanism. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

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 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

Based on directives of regulatory commissions, the Company reflected investment tax credits in rates on a deferral basis. Commensurate with rate treatment deferred investment tax credits are being amortized over the life of the related plant investment. The Company's policy with regard to investment tax credits for nonutility property was to practice the flow-through method of accounting.

Debt

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

Debt discount or premium and debt issuance expenses 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.

2. COMMITMENTS AND CONTINGENCIES:

Construction

Construction expenditures for the years 1997-1999 are estimated to be $191 million and, in connection therewith, certain commitments have been made.

Fuel Supply

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. The fuel adjustment mechanism generally provides for recovery of changes in the cost of fuel.

Loan Guarantees

A constructive marketing program enables residential customers to borrow from area banks to purchase energy efficient electrical equipment, such as heat pumps. KPCo guarantees loan principal plus interest. The guaranteed amounts totaled $14.6 million at December 31, 1996.

Litigation

KPCo is involved in a number of 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 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 1999. The agreement provides for the Company to purchase 15% of the total output of the two unit 2,600-mw capacity Rockport 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.

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Demand charges and energy purchases under the Unit Power Purchase Agreement were included in purchased power expense as follows:

	Year Ended December 31, 1996	1995
	(in thousands)	
Demand Charge	$39,622	$39,608
Energy Charge	27,743	29,027
Total	$67,365	$68,635

Benefits and costs of the System's generating plants are shared by members of the AEP System 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 Power Pool members based on their relative peak demands and generating reserves. Power Pool members are compensated for the out-of-pocket costs of energy delivered to the Power Pool and charged for energy received from the Power Pool.

Operating revenues include $28.0 million in 1996 and $38.9 million in 1995 for energy supplied to the Power Pool.

Charges for Power Pool capacity, which is a charge for the right to receive power and payable even if the power is not taken, and for energy received from the Power Pool were included in purchased power expense as follows:

	Year Ended December 31, 1996	1995
	(in thousands)	
Capacity Charge	$ 6,425	$ 6,489
Energy Charge	19,741	9,493
Total	$26,166	$15,982

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Power Pool members share in wholesale sales to unaffiliated entities made by the Power Pool. The Company's share of these wholesale power pool sales was included in operating revenues in the amount of $26.7 million in 1996 and $19.2 million in 1995.

In addition, the Power Pool purchases power from unaffiliated companies for immediate resale to other unaffiliated utilities. The Company's share of these purchases was included in purchased power expense and totaled $3.0 million in 1996 and $3.9 million in 1995. Revenues from these transactions including a transmission fee are included in the above Power Pool wholesale operating revenues.

AEP System companies participate in a 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, other operating expense includes equalization credits of $3.3 million and $3.5 million in 1996 and 1995, respectively.

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed by AEPSC on a direct-charge basis to the extent practicable, and on reasonable bases of proration for indirect costs. The charges 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.

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4. BENEFIT PLANS:

KPCo participates in the AEP System pension plan, a trusteed, noncontributory defined benefit plan covering all employees meeting eligibility requirements. Benefits are based on service years and compensation levels. Pension costs are allocated by first charging each System company with its service cost and then allocating the remaining pension cost in proportion to its share of the projected benefit obligation. The funding policy is to make annual trust fund contributions equal to the net periodic pension cost up to the maximum amount deductible for federal income taxes, but not less than the minimum required contribution in accordance with the Employee Retirement Income Security Act of 1974. Net pension plan costs for the years ended December 31, 1996 and 1995 were $812,000 and $573,000, respectively.

An employee savings plan is offered which allows participants to contribute up to 17% of their salaries into various investment alternatives, including AEP Co., Inc. common stock. An employer matching contribution, equaling one-half of the employees' contribution to the plan up to a maximum of 3% of the employees' base salary, is invested in AEP Co., Inc. common stock. The Company's annual contributions totaled $687,000 in 1996 and $720,000 in 1995.

Postretirement benefits other than pensions (OPEB) are provided for retired employees under an AEP System plan. Substantially all employees are eligible for postretirement health care and life insurance if they retire from active service after reaching age 55 and have at least 10 service years. OPEB costs are determined by the application of AEP System actuarial assumptions to each operating company's employee complement. The annual accrued costs, which includes the recognition of one-twentieth of the prior service transition obligation, were $2.8 million in 1996 and $2.4 million in 1995. The funding policy for AEP's OPEB plan is to make contributions to an external Voluntary Employees Beneficiary Association trust fund equal to the incremental OPEB costs (i.e., the amount that the total postretirement benefits cost under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," exceeds the pay-as-you-go amount). Contributions were $1.3 million in 1996 and $1.6 million in 1995.

5. COMMON SHAREHOLDER'S EQUITY:

The Company received from AEP Co., Inc. cash capital contributions of $30 million in 1996 and $10 million in 1995 which were credited to paid-in capital. There were no other transactions affecting common stock and paid-in capital accounts in 1996 and 1995.

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6. FEDERAL INCOME TAXES:

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

	Year Ended December 31, 1996	1995
	(in thousands)	
Charged (Credited) to Operating Expenses (net):		
Current	$ 5,118	$ 7,935
Deferred	1,857	(2,373)
Deferred Investment Tax Credits	(1,232)	(1,243)
Total	5,743	4,319
Charged (Credited) to Nonoperating Income (net):		
Current	(473)	(163)
Deferred	7	(7)
Deferred Investment Tax Credits	(158)	(235)
Total	(624)	(405)
Total Federal Income Taxes as Reported	$ 5,119	$ 3,914

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.

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	Year Ended December 31, 1996	1995
	(in thousands)	
Net Income	$16,973	$25,128
Federal Income Taxes	5,119	3,914
Pre-tax Book Income	$22,092	$29,042
Federal Income Taxes on Pre-tax Book Income at Statutory Rate (35%)	$ 7,732	$10,165
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:		
Depreciation	1,694	(648)
Removal Costs	(979)	(979)
Amortization of Deferred Federal Income Tax in Excess of the Statutory Tax Rate	(339)	(1,355)
Allowance For Funds Used During Construction	(389)	(390)
Percentage Repair Allowance	(445)	(433)
Corporate Owned Life Insurance	(479)	(826)
Investment Tax Credits (net)	(1,390)	(1,478)
Other	(286)	(142)
Total Federal Income Taxes as Reported	$ 5,119	$ 3,914
Effective Federal Income Tax Rate	23.2%	13.5%

NOTES TO FINANCIAL STATEMENTS (Continued)

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

	December 31, 1996	December 31, 1995
	(in thousands)	
Deferred Tax Assets	$ 30,919	$ 29,653
Deferred Tax Liabilities	(184,457)	(174,658)
Net Deferred Tax Liabilities	$(153,538)	$(145,005)
Property Related Temporary Differences	$(108,276)	$(105,234)
Amounts Due From Customers For Future Federal Income Taxes	(18,734)	(18,228)
Deferred State Income Taxes	(30,711)	(25,487)
All Other (net)	4,183	3,944
Total Net Deferred Tax Liabilities	$(153,538)	$(145,005)

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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 Internal Revenue Service (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 1993 are presently being audited by the IRS. During the audit the IRS agents requested a ruling from their National Office that certain interest deductions relating to corporate owned life insurance (COLI) claimed by the Company for 1991 through 1993 should not be allowed. The COLI program was established in 1992 as part of the Company's strategy to fund and reduce the cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1996 would reduce earnings by approximately $5 million (including interest). Management believes it will ultimately prevail on this issue and will vigorously contest any adjustments that may be assessed. Accordingly, no provision for this amount has been recorded. In the opinion of management, the final settlement of open years will not have a material effect on results of operations.

7. LEASES:

Leases of property, plant and equipment are for periods 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 are generally charged to operating expenses in accordance with rate-making treatment. The components of rental costs are as follows:

	Year Ended December 31, 1996	1995
	(in thousands)	
Operating Leases	$ 402	$ 564
Amortization of Capital Leases	2,652	2,111
Interest on Capital Leases	707	513
Total Rental Costs	$3,761	$3,188

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

	December 31, 1996	1995
	(in thousands)	
Electric Utility Plant:		
Production	$ 1,586	$ 1,352
General	18,475	13,731
Total Electric Utility Plant	20,061	15,083
Accumulated Amortization	7,211	5,664
Net Properties under Capital Lease	$12,850	$ 9,419
Capital Lease Obligations:		
Noncurrent Liability	$ 9,833	$7,064
Liability Due Within One Year	3,017	2,355
Total Capital Lease Obligations	$12,850	$9,419

Capital lease obligations are included in other noncurrent and other current liabilities on the Balance Sheets. Properties under operating leases and related obligations are not included in the Balance Sheets.

NOTES TO FINANCIAL STATEMENTS (Continued)

Future minimum lease payments consisted of the following at December 31, 1996:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
1997	$ 3,651	$ 492
1998	2,961	286
1999	2,499	160
2000	1,943	98
2001	1,208	11
Later Years	2,388	-
Total Future Minimum Payments	14,650	$1,047
Less Estimated Interest Element	1,800	
Estimated Present Value of Future Minimum Lease Payments	$12,850	

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8. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt was outstanding as follows:

	December 31, 1996	December 31, 1995
	(in thousands)	
First Mortgage Bonds:		
5 1/8% due January 1, 1996	$ -	$ 29,436
7.20% due December 1, 1999	35,000	35,000
8.95% due May 10, 2001	20,000	20,000
8.90% due May 21, 2001	40,000	40,000
7 7/8% due September 1, 2002	-	45,000
6.65% due May 1, 2003	15,000	15,000
6.70% due June 1, 2003	15,000	15,000
6.70% due July 1, 2003	15,000	15,000
7.90% due June 1, 2023	15,000	15,000
7.90% due June 1, 2023	25,000	25,000
Unamortized Discount (net)	(695)	(765)
Total	179,305	253,671
Notes Payable to Banks:		
6.42% due April 1, 1999	25,000	-
6.57% due April 1, 2000	25,000	-
7.445% due September 20, 2002	25,000	-
Total	75,000	-
Junior Subordinated Deferrable Interest Debentures 8.72% Series A due June 30, 2025	40,000	40,000
Unamortized Discount	(1,107)	(1,146)
Total	38,893	38,854
Less Portion Due Within One Year	-	29,436
Total	$293,198	$263,089

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.

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At December 31, 1996 annual long-term debt payments, excluding premium and discount, are as follows:

	Principal Amount (in thousands)
1997	$ -
1998	-
1999	60,000
2000	25,000
2001	60,000
Later Years	150,000
Total	$295,000

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, 1996 and 1995 were available in the amounts of $409 million and $372 million, respectively. Commitment fees of approximately 1/8 of 1% of the unused short-term lines of credit are paid each year to the banks to maintain the lines of credit. Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1996:		
Notes Payable	$33,800	6.1%
Commercial Paper	17,875	6.5%
Total	$51,675	6.2%
December 31, 1995:		
Notes Payable	$15,950	6.1%
Commercial Paper	11,100	6.1%
Total	$27,050	6.1%

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9. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The carrying amount of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximates fair value because of the short-term maturities of these instruments.

At December 31, 1996 and 1995 the fair value of long-term debt was $304 million and $307 million, respectively, based on quoted market prices for the same or similar issues and the current interest rates offered for debt of the same remaining maturities.

The carrying amount for long-term debt was $293.2 million and $292.5 million at December 31, 1996 and 1995, respectively.

10. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1996 (in thousands)
Cash was paid for:	
Interest (net of capitalized amounts)	$24,069
Income Taxes	9,012
Noncash Acquisitions under Capital Leases were	6,322

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

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	$876,278,000	$876,278,000
4	Property Under Capital Leases	12,849,848	12,849,848
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	TOTAL (Enter Total of lines 3 thru 7)	$889,127,848	$889,127,848
9	Leased to Others		
10	Held for Future Use	6,862,819	6,862,819
11	Construction Work in Progress	48,400,480	48,400,480
12	Acquisition Adjustments		
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	$944,391,147	$944,391,147
14	Accum. Prov. for Depr., Amort., & Depl.	279,428,995	279,428,995
15	Net Utility Plant (Enter Total of line 13 less 14)	$664,962,152	$664,962,152
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation	279,390,269	279,390,269
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights		
20	Amort. of Underground Storage Land and Land Rights		
21	Amort. of Other Utility Plant	38,726	38,726
	TOTAL In Service (Enter Total of lines 18 thru 21)	$279,428,995	$279,428,995
	eased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Aquisition Adj.		
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31 and 32)	$279,428,995	$279,428,995

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Gas (d)	Other(Specify) (e)	Other(Specify) (f)	Other(Specify) (g)	Common (h)	Line No.
[redacted]					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
[redacted]					16
					17
					18
	[redacted]				19
					20
					21
[redacted]					
					24
					25
					26
[redacted]					27
					28
					29
					30
	[redacted]				31
					32
					33

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ELECTRIC PLANT IN SERVICE (Accounts 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

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	0	
3	(302) Franchises and Consents	40,930	1,866
4	(303) Miscellaneous Intangible Plant	0	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$40,930	$1,866
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,545	
9	(311) Structures and Improvements	26,736,505	351,661
10	(312) Boiler Plant Equipment	128,113,462	16,029,318
	(313) Engines and Engine-Driven Generators	0	
	(314) Turbogenerator Units	55,577,200	126,815
	(315) Accessory Electric Equipment	12,390,642	12,996
14	(316) Misc. Power Plant Equipment	4,808,147	39,964
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	$228,702,501	$16,560,754
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	0	
18	(321) Structures and Improvements	0	
19	(322) Reactor Plant Equipment	0	
20	(323) Turbo generator Units	0	
21	(324) Accessory Electric Equipment	0	
22	(325) Misc. Power Plant Equipment	0	
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	0	
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	0	
26	(331) Structures and Improvements	0	
27	(332) Reservoirs, Dams, and Waterways	0	
28	(333) Water Wheels, Turbines, and Generators	0	
29	(334) Accessory Electric Equipment	0	
30	(335) Misc. Power Plant Equipment	0	
31	(336) Roads, Railroads, and Bridges	0	
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	0	
33	D. Other Production Plant		
34	(340) Land and Land Rights	0	
35	(341) Structures and Improvements	0	
36	(342) Fuel Holders, Products, and Accessories	0	
	(343) Prime Movers	0	
	(344) Generators	0	
39	(345) Accessory Electric Equipment	0	

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

...ersals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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. In showing the clearance of 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 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 requirements 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 purchaser, 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
			0	(301)	2
			42,796	(302)	3
			0	(303)	4
			$42,796		5
[redacted]					6
					7
			1,076,545	(310)	8
94,931			26,993,235	(311)	9
1,467,328			142,675,452	(312)	10
			0	(313)	11
477,746			55,226,269	(314)	1.
(5,952)			12,409,590	(315)	13
9,510			4,838,601	(316)	14
$2,043,563			$243,219,692		15
[redacted]					16
			0	(320)	17
			0	(321)	18
			0	(322)	19
			0	(323)	20
			0	(324)	21
			0	(325)	22
			0		23
[redacted]					24
			0	(330)	25
			0	(331)	26
			0	(332)	27
			0	(333)	28
			0	(334)	29
			0	(335)	30
			0	(336)	31
			0		32
[redacted]					33
			0	(340)	34
			0	(341)	35
			n	(342)	36
				(343)	3
				(344)	38
				(345)	39

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

	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	0	
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	0	
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	$228,702,501	$16,560,754
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	22,071,053	71,722
45	(352) Structures and Improvements	4,806,335	117,748
46	(353) Station Equipment	57,600,564	2,503,976
47	(354) Towers and Fixtures	77,166,239	(19,575)
48	(355) Poles and Fixtures	21,133,070	(13,609)
49	(356) Overhead Conductors and Devices	78,724,005	303,786
50	(357) Underground Conduit	11,590	
51	(358) Underground Conductors and Devices	106,066	
52	(359) Roads and Trails	0	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	$261,618,922	$2,964,048
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	3,746,131	30,420
56	(361) Structures and Improvements	3,559,048	(117,748)
57	(362) Station Equipment	31,866,404	1,812,458
58	(363) Storage Battery Equipment	0	
59	(364) Poles, Towers, and Fixtures	89,025,187	10,898,786
60	(365) Overhead Conductors and Devices	66,445,999	3,270,420
61	(366) Underground Conduit	1,659,007	131,833
62	(367) Underground Conductors and Devices	2,956,467	190,902
	(368) Line Transfomers	66,952,866	3,287,901
	(369) Services	17,635,192	816,459
	(370) Meters	20,547,762	669,427
66	(371) Installations on Customer Premises	7,154,687	508,756
67	(372) Leased Property on Customer Premises	0	
68	(373) Street Lighting and Signal Systems	2,234,444	50,186
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	$313,783,194	$21,549,800
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	2,414,398	(45,954)
72	(390) Structures and Improvements	29,922,271	171,199
73	(391) Office Furniture and Equipment	897,287	
74	(392) Transportation Equipment	251,106	
75	(393) Stores Equipment	159,597	
76	(394) Tools, Shop and Garage Equipment	684,739	
77	(395) Laboratory Equipment	393,393	28,363
78	(396) Power Operated Equipment	0	
79	(397) Communication Equipment	3,971,257	774,547
80	(398) Miscellaneous Equipment	282,408	
81	SUBTOTAL (Enter Total of lines 71 thru 80)	$38,976,456	$928,155
82	(399) Other Tangible Property	0	
83	TOTAL General Plant (Enter Total of lines 81 and 82)	$38,976,456	$928,155
84	TOTAL (Accounts 101 and 106) (lines 5,15,23,32,41,53,69,83)	$843,122,003	$42,004,623
85	(102) Electric Plant Purchased (See Instr. 8)		
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)	$843,122,003	$42,004,623

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of year (g)		L N
			0	(346)	40
			0		41
$2,043,563			$243,219,692		42
[redacted]					43
		6,013	22,148,788	(350)	44
			4,924,083	(352)	45
35,860			60,068,680	(353)	46
894			77,145,770	(354)	47
58,862			21,060,599	(355)	48
40,165		109,451	79,097,077	(356)	49
			11,590	(357)	50
			106,066	(358)	51
			0	(359)	52
$135,781		$115,464	$264,562,653		53
[redacted]					54
		(3,943)	3,772,608	(360)	55
5,309			3,435,991	(361)	56
471,299		(14,778)	33,192,785	(362)	57
			0	(363)	58
1,128,837			98,795,136	(364)	59
1,662,236			68,054,183	(365)	60
3,248			1,787,592	(366)	61
37,421			3,109,948	(367)	62
1,578,917		14,778	68,676,628	(368)	63
475,561			17,976,090	(369)	
517,207			20,699,982	(370)	65
246,115			7,417,328	(371)	66
			0	(372)	67
18,665			2,265,965	(373)	68
$6,144,815		($3,943)	$329,184,236		69
[redacted]					70
		(2,070)	2,366,374	(389)	71
290,552			29,802,918	(390)	72
4,438			892,849	(391)	73
			251,106	(392)	74
			159,597	(393)	75
734			684,005	(394)	76
7,565			414,191	(395)	77
			0	(396)	78
157,954		(109,451)	4,478,399	(397)	79
63,224			219,184	(398)	80
$524,467		($111,521)	$39,268,623		81
			0	(399)	82
$524,467		($111,521)	$39,268,623		83
$8,848,626	0	0	$876,278,000		84
[redacted]				(102)	85
					86
				(103)	87
$8,848,626	0	0	$876,278,000		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				
16				
17				
18				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
	TOTAL			$6,862,819

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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 Demonstration (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	Install Remote Terminal Units	$166,301
2	Build 138KV Extension for Baker-Big Sandy	553,016
3	Construct Big Sandy-Inez 138KV Line ATP-9S	384,225
4	RGL Trans to Baker Station	1,356,269
5	Install Two 138KV Breakers-Big Sandy	1,936,207
6	Build Digital Microwave System	531,394
7	Install Reactor at Leslie Station	1,145,175
8	Replace 69/12KV Transformer with 69/34 & add 34.5 Recloser	816,834
9	Construct New Line to Reedy Station	131,713
10	System Restoration Project	116,410
11	Install & Replace Microwave Equipment	333,041
12	Right of Way for Big Sandy-Inez 138KV Trans	604,919
13	Install 16MVAR Statcom at Inez 138KV P-9S	17,670,036
14	Install 3 Breakers-Inez Station	376,628
15	Construct Allen-Preston Burg 46KV Circuit	191,186
16	Replace Cooling Tower Wood Frame Str U2	10,586,685
17	Big Sandy U-2 Replace Economizer Outlet Flues, Huppers & G&P Joint	2,842,721
18	Minor Projects Less than $100,000	8,657,720
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
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37		
38		
39		
40		
41		
42		
43	TOTAL	$48,400,480

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CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the 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)
2	1. Kinds of Overheads	
4	(A) Engineering, Technical and Drafting Service -	
5	American Electric Power Service Corporation	
6	applicable to non-steam construction	4,602,858
8	(B) Engineering, Technical and Drafting Service -	
9	American Electric Power Service Corporation	
10	applicable to steam plant construction	1,386,568
12	(C) Company Construction Overheads applicable	
13	to non-steam plant construction	6,027,758
15	(D) Company Construction Overheads applicable to	
16	steam plant construction	383,806
	(E) Plant Capital Overheads applicable to	
	steam plant construction	874,389
	TOTAL	$13,275,379

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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature d 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 fund 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 Page 218 Footnote.1

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COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

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

1. ponents 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	S		
(2)	Short-Term Interest			s
(3)	Long-Term Debt	D		d
(4)	Preferred Stock	P		p
(5)	Common Equity	C		c
(6)	Total Capitalization		100%	
(7)	Average Construction Work in Progress Balance	W		

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

3. Rate for Other Funds

$$\left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$$

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds -

b. Rate for Other Funds -

< Page 218 Line 1 Column a >

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

A. Engineering and Supervision (American Electric Power Service Corporation) applicable to non-steam plant construction.

(a) Overheads "Engineering, Technical and Drafting Services" are engineering services performed by the Engineering Department of American Electric Power Service Corporation applicable to non-steam plant construction.

(b) In accordance with provisions of a service agreement between American Electric Power Service Corporation (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 timekeeping and other specific cost identification are economically feasible, and

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

(c) 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. Engineering and Supervision (American Electric Power Service Corporation) applicable to steam plant construction.

(a) Overheads "Engineering, Technical and Drafting Services" are engineering services performed by the Engineering Department of American Electric Power Service Corporation applicable to steam plant construction.

(b) In accordance with provisions of a service agreement between American Electric Power Service Corporation (AEPSC) and the respondent, approved by the Securities & Exchange Commission February 19, 1981, salaries,

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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 timekeeping and other specific cost identification are economically feasible, and

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

(c) 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. Company Construction Overheads applicable to non-steam construction.

(a) Charges representing salaries and expenses of Company's administrative and general, engineering, supervision and related drafting and technical work applicable to non-steam construction.

(b) Partly on basis of time and work studies and partly on basis of daily time records.

(c) 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 expenditures.

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

(f) See note (c).

D. Company Construction Overheads applicable to steam plant construction.

(a) Charges representing cost of Company's engineering and supervision applicable to steam plant construction.

(b) Partly on basis of time and work studies and partly on basis of daily time records.

(c) 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 expenditures.

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

(f) See note (c).

E. 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 charges to such projects.

(d) A uniform rate is applied to all subject construction 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 (d), 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 retire 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	$264,887,438	$264,887,438		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	25,084,571	25,084,571		
4	(413) Exp. of Elec. Plt.Leas.to Others				
5	Transportation Expenses—Clearing				
6	Other Clearing Accounts	2,496	2,496		
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	$25,087,067	$25,087,067		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	(9,570,154)	(9,570,154)		
	Cost of Removal	(3,437,057)	(3,437,057)		
	Salvage (Credit)	1,232,118	1,232,118		
	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	($11,775,093)	($11,775,093)		
15	Other Debit or Cr.Items (Describe):	1,190,857	1,190,857		
16					
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$279,390,269	$279,390,269		
	Section B. Balances at End of Year According to Functional Classifications				
18	Steam Production	125,842,641	125,842,641		
19	Nuclear Production	0			
20	Hydraulic Production-Conventional	0			
21	Hydraulic Production-Pumped Storage				
22	Other Production				
23	Transmission	72,645,068	72,645,068		
24	Distribution	70,264,968	70,264,968		
25	General	10,637,592	10,637,592		
26	TOTAL (Enter Total of lines 18 thru 25)	$279,390,269	$279,390,269		

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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 Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	Property previously devoted to Public Service:			0
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			0
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			
	Transferred 1975	2,051		2,051
	R/W for Savage Branch-South Neal 138kv Line,			
	Boyd County, Kentucky, Transferred 1971	2,225		2,225
21				
22	R/W for 345kv Corridor in Trimble County,			
23	Kentucky, Transferred 1982	330,782		330,782
24				
25	Land Purchased for R/W for 345kv 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				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
	Minor Item Previously Devoted to Public Service			
	Minor Items-Other Nonutility Property			
	TOTAL	$973,644	0	$973,644

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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)	$3,422,429	$8,806,227	
2	Fuel Stock Expenses Undistributed (Account 152)	103,896	437,997	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	4,207,721	3,511,053	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,892,142	3,247,724	
8	Transmission Plant (Estimated)	315,579	263,329	
9	Distribution Plant (Estimated)	1,577,895	1,316,645	
10	Assigned to - Other	525,965	438,882	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	$10,519,302	$8,777,633	
12	Merchandise (Account 155)	28,000	0	
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	194,868	(288,049)	
16				
	TOTAL Materials and Supplies (Per Balance Sheet)	$14,268,495	$17,733,808	

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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 eligble 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)

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	1997 No. (d)	1997 Amt. (e)
01	Balance-Beginning of Year	18,916.00	$1,738,953		
02 03 04	Acquired During Year: Issued (Less Withheld Allow.)	0	0		
05	Returned by EPA	0	0		
06 07 08	Purchases/Transfers: Ohio Power	27,777.00	2,935,354		
09	Columbus Southern Power	250.00	37,106		
10					
11					
12					
13					
14					
15	Total	28,027.00	$2,972,460		
16 17 18	Relinquished During Year: Charges to Account 509	0	0		
	Other:	0	0		
	Cost of Sales/Transfers: Ohio Power	782.00	65,343		
23	Indiana & Michigan Power	86.00	7,180		
24					
25					
26					
27					
28	Total	868.00	$72,523		
29	Balance-End of Year	46,075.00	$4,638,890	0	0
30 31 32	Sales: Net Sales Proceeds (Assoc. Co.)		72,523		
33	Net Sales Proceeds (Other)		0		
34	Gains		0		
35	Losses		0		
	Allowances Withheld (Account 158.2)	[redacted]			
36	Balance-Beginning of Year	0	0		
37	Add: Withheld by EPA	0	0		
38	Deduct: Returned by EPA	0	0		
39	Cost of Sales	0	0		
40	Balance-End of Year	0	0	0	0
41 42 43	Sales: Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		0		
	Gains		0		
	Losses		0		

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Allowances (Accounts 158.1 and 158.2) (Continued)

ed allowances. Report withheld portions lines 36-40

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 acquired 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 and 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 & 43-46 the net sales proceeds and gains or losses from allowance sales.

1998		1999		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
				658,340.00	0	677,256.00	$1,738,953	01
				24,935.00	0	24,935.00	0	02 03 04
				0	0	0	0	05
						27,777.00	2,935,354	06 07 08
				323.00	46,836	573.00	83,942	09
								10
								11
								12
								13
								14
				323.00	$46,836	28,350.00	$3,019,296	15
						0	0	16 17 18
						0	0	
						0	0	
						782.00	65,343	21 22
						86.00	7,180	23
								24
								25
								26
								27
						868.00	$72,523	28
0	0	0	0	683,598.00	$46,836	729,673.00	$4,685,726	29
						0	72,523	30 31 32
						0	0	33
						0	0	34
						0	0	35
[redacted]								
				17,737.00	0	17,737.00	0	36
					0	0	0	37
				0	0	0	0	38
				362.00	0	362.00	0	39
0	0	0	0	17,375.00	0	17,375.00	0	40
						0	0	41 42 43
					23,296	0	23,296	44
					23,296	0	23,296	
					0	0	0	

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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 ratemaking 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	$205,213	var	$331,837	$71,323,182
2	Unamortized Dumont UHV Test Costs		401	57,826	0
3	VEBA Trust Contributions		401	532,012	0
4	Depreciation Expenses-Hanging Rock/Jefferson				
5	765Kv Line		VAR	5,208	187,057
6	Post In-Service AFUDC-Hanging Rock/Jefferson				
7	765Kv Line		406	33,408	1,200,168
8	Deferred DSM Expense	791,045	401	1,603,835	(812,790)
9	Post Employment Benefits	980,695	228	0	3,072,884
10	SFAS 109 Deferred State Income Tax	5,224,000			30,711,000
11	Miscellaneous	1,431	VAR	3,729	0
12	Carrying Charges - Purchased Allowances	15,727			15,727
13					
14					
15					
16					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
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36					
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38					
39					
40					
41					
42					
	TOTAL	$7,218,111		$2,567,855	$105,697,228

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MISCELLANEOUS DEFERRED 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 items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDIT Account Charged (d)	CREDIT Amount (e)	Balance at End of Year (f)
1	Accrual ADjustment					
2	Ky Real Estate Personality &					
3	Franchise Tax	4,704,000	4,920,000	408	4,704,000	4,920,000
4						
5	Constructive Marketing Program-					
6	ETS	230,074	439	143	218,500	12,013
7				426		
8						
9	Constructive Marketing Program	3,070	203,661	124	206,731	0
10						
11	Constructive Marketing Program-					
12	Insider Heat Pump	395,328		426	395,328	0
13				143		
14						
15	Unmatched Procurement Card					
16	Transactions	(13,146)	558,404		584,335	(39,077)
17						
18	Miscellaneous Deferred Expenses	978,752	4,030		982,448	334
19						
	Minor Items	(12,038)	16,023	VAR	629	3,3
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
47	Misc. Work in Progress	568,992	[redacted]			1,302,53
48	DEFERRED REGULATORY COMM. EXPENSES (See pages 350-351)					
	TOTAL	$6,855,032	[redacted]			$6,199,157

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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.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Interest Expense Capitalized	$1,070,344	$1,383,774
3	Contribution-In-Aid-of-Construction	1,379,608	1,488,649
4	Customer Advances	(2,892)	7,565
5	Deferred Fuel	255,780	480,361
6	INA Insurance Cost	1,252,329	737,268
7	Other	* 3,518,282	3,661,392
8	TOTAL Electric (Enter Total of lines 2 thru 7)	$7,473,451	$7,759,009
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	0
17	Other *	22,179,399	23,159,579
18	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$29,652,850	$30,918,588

NOTES

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OTHER - LINE 7

KENTUCKY POWER COMPANY

	BEGINNING OF YEAR	END OF YEAR
Provision for Uncollectible Accounts	$ 81,176	$ 95,214
Tax on Accured Payroll	13,370	12,712
Advance Rental Income	671	760
IRS Audit Settlements	999,172	575,122
Provision for Worker's Compensation Costs	155,093	(2,303)
Acrued Book Pension Expense	1,079,821	1,323,456
Deferred Compensation	48,883	45,379
Accrued Vacation Pay	665,071	833,654
Management Incentive Bonus	128,467	109,756
Accrued Asbestos Lawsuit	30,654	30,654
Accrued Book Sup. Savings Plan Exp.	148	442
Accrued Book Severance Benefits	311,358	0
SFAS 106 Post Retirement Benefit	6	418,439
Cap. Carrying Chg.-Def.Book Gain-EMA	4,392	3
Accrued PSI Plan Expense	0	29,750
Bk Loss Prov - Plant M&S	0	128,348
Tax > Book Basis - EMA	0	25,383
Deferred Bolivia Project Costs - Tax	0	31,238
Bk Amort Dumont Test Ctr - Norm	0	3,385
TOTAL LINE 7	$3,518,282	$3,661,392

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< Page 234 Line 17 Column B & C)

OTHER - LINE 17

Provision for Uncollectible Accounts - Account 190.2	68,638	70,176
Book Provision Loss on E-Lamp	9,800	0
SUB-TOTAL	78,438	70,176
SFAS 109 Regulatory Asset - - Account 190.3 & 190.4	22,100,961	23,089,403
TOTAL LINE 17	22,179,399	23,159,579

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CAPITAL STOCK (Accounts 201 and 204)

. 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 Exchange (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	
	TOTAL_COM	2,000,000		

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CAPITAL STOCK (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 noncumulative.

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
						7
						8
						9
						10
						11
						12
						13
						14
						1[illegible]
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						39
						4[illegible]
1,009,000	50,450,000	0	0	0	0	4[illegible]

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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 debt 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	Donations Received From Stockholders Account 208	
2		
3	Contributions by Parent Company:	
4		
5	Prior to 1996	78,750,000
6	Cash Contributions in 1996:	
7	Cash Contribution in 1996 (General Corporate Obligations Including Construction Expenditures)	10,000,000
8	Authorized by: SEC Order Date 12/31/93, No. 70-8293, Release No. 35-25957	
9		
10	Cash Contribution in 1996 (Capital Contributions Without Interest)	20,000,000
11	Authorized by: SEC Order Date 06/25/95, No. 250.45 (b) (4),60 FR 33639	
	SUBTOTAL	108,750,000
	Account 209 - Reduction in Par or Stated Value of Capital Stock	0
16		
17	Account 210 - Gain on Resale or Cancellation of Reaquired Capital Stock	0
18		
19	Account 211 - Miscellaneous Paid-in Capital	0
20		
21		
22		
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24		
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36		
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	TOTAL	$108,750,000

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

LONG-TERM DEBT (Accounts 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 7 7/8% Series	$45,000,000	$89,302
2			(166,100) P
3	First Mortgage Bonds 8.95% Series	20,000,000	78,933
4			125,000 D
5	First Mortgage Bonds 8.90% Series	40,000,000	157,870
			250,000 D
	First Mortgage Bonds 7.20% Series	35,000,000	263,125
			210,000 D
	First Mortgage Bonds 6.65% Series	15,000,000	78,937
10			93,750 D
11	First Mortgage Bonds 6.70% Series	15,000,000	48,113
12			93,750 D
13	First Mortgage Bonds 7.90% Series	15,000,000	48,113
14			112,500 D
15	First Mortgage Bonds 7.90% Series	25,000,000	80,188
16			187,500 D
17	First Mortgage Bonds 6.70% Series	15,000,000	48,113
18			93,750 D
19			
20	Junior Subordinated Deferrable Debentures		
21	8.72% Series (See Order 33-58313 Dated 4-6-95		
22	and KY PSC Order 94-035 Dated 1-31-94)	40,000,000	178,044
23			1,175,188 D
24	Account 221		
25	Subtotal	265,000,000	3,246,076
26			
27	Account 224		
28	Term Loan Bank of NY 6.42%	25,000,000	
29	Term Loan Bank of NY 6.57%	25,000,000	
30	Term Loan Societe Generale 7.445%	25,000,000	
31			
	TOTAL	$340,000,000	$3,246,076

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

10. ify separate undisposed amounts applicable to issue: ch were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (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) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
09/01/72	09/01/02	09/01/72	09/01/02	0	876,094	1
						2
05/10/91	05/10/01	05/10/91	05/10/01	20,000,000	1,790,004	3
						4
05/20/91	05/21/01	05/20/91	05/21/01	40,000,000	3,560,004	5
12/01/92	12/01/99	12/01/92	12/01/99	35,000,000	2,520,000	
						8
04/23/93	05/01/03	04/23/93	05/01/03	15,000,000	997,500	9
						10
05/20/93	06/01/03	05/20/93	06/01/03	15,000,000	1,005,000	11
						12
05/20/93	06/01/23	05/20/93	06/01/23	15,000,000	1,185,000	13
						14
06/09/93	06/01/23	06/09/93	06/01/23	25,000,000	1,974,996	15
						16
06/24/93	07/01/03	06/24/93	07/01/03	15,000,000	1,005,000	17
						18
						19
04/20/95	06/30/25	04/20/95	06/30/25	40,000,000	3,488,004	20
						21
						22
						23
						24
				220,000,000	18,401,602	25
						26
						27
	04/01/99			25,000,000	1,203,750	28
	04/01/00			25,000,000	1,231,875	29
	09/20/02			25,000,000	522,184	30
						31
						3
[redacted]				$295,000,000	$21,359,411	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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, 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)	$16,972,985
2	Reconciling Items for the Year	
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		
	Income Recorded on Books Not Included in Return	
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	* 18,970,669
28	Show Computation of Tax:	
29		
30		
31		
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42		

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KENTUCKY POWER COMPANY

Income for the Year (Page 117)		16,972,985
Total Federal Income Taxes		5,118,756
Pre-Tax Book Income		22,091,741
Increase(Decrease) in Taxable Income Resulting From:		
Excess of Tax Over Book Depreciation		(2,773,197)
Allowance for Funds Used During Construction & Miscellaneous Items Capitalized on the Books but Deducted for Tax Purposes		197,637
Removal Cost		(2,796,000)
Deferred Fuel		506,908
Changes to Clearing Accounts (Net)		191,386
Reserve for Self Insurance (Net)		(421,687)
Uncollectible Accounts (Net)		12,551
Taxes on Accrued Payroll		(1,880)
Deferred Compensation (Net)		(31,416)
Uncollectible Accounts (Net) - O.I.D.		434
BK Loss Prov - Plant M&S		366,708
Vacation Pay (Net)		236,586
Accrued Mgt. Incentive Bonus		485,092
Paid Severance Benefits		(889,595)
Reversal Bk Prov E-Lamp Loss		(28,000)
Pension Trust Expense		812,450
Accrued PSI Plan Exp		85,000
Advance Rental (Net)		253
Excess Tax Versus Book Gain		373,863
Emmission Allowances (Net)		(103,079)
Loss on Reacquired Debt (Net)		(166,002)
Non Deductible Meals, Travel & Memberships		260,928
Corporate Owned Life Insurance		(1,368,977)
Post Retirement Benefits		1,839,715
Defd Bolivia Project Costs - tax		89,250
Federal Tax Net Income-Estimated Current Year Taxable Income		18,970,669
Show Computation of Tax:		
Federal Income Tax on Current Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		6,639,734
Adjustment Due to System Consolidation	(a)	(41,446)
Estimated Currently Payable	(b)	6,598,288
Adjustments of Prior-Year Accruals(Net)		(1,953,412)
Estimated Current Federal Income Tax Expense		4,644,876

(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.

(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 Company, Inc. is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the 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 1996 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed in September, 1997. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until October, 1997.

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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) 12/31/96	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and ued tax accounts and show the total taxes charged to ations 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	1,632,219	0	4,644,876	7,156,512	0
3						
4	Unemployment Ins. - 1995	2,124	0	(2,124)	0	0
5	Unemployment Ins. - 1996	0	0	48,044	45,303	0
6						
7	Ins. Contrib. Act 1995	72,589	0	(34,390)		0
8	Ins. Contrib. Act. 1996		0	2,834,701	2,805,194	0
9						
10	Env. Excise Tax 1995	11,368	0	(2,409)	8,959	0
11	Env. Excise Tax 1996	0	0	26,000	35,032	0
	STATE OF KENTUCKY					
	Taxes on Income	315,632	0	1,062,541	1,856,360	
	City of Morehead Tax		25	25		
16	PSC Maint.Rem.Asst.1996		193,118	359,648	333,066	0
17						
18	Unemp. Ins. - 1995	1,021	0	(1,021)		0
19	Unemp. Ins. - 1996		0	27,016	25,669	0
20						
21	Intang. Prop. Tax - 1996		0	0	0	0
22						
23	Real & Pers.Prop. 1993	61,356	0	0	0	0
24	Real & Pers.Prop. 1994	94,859	0	55,357	150,216	0
25	Real & Pers.Prop. 1995	1,078,986	0	123,125	1,127,111	0
26	Real & Pers.Prop. 1996	4,704,000	0	41,400	3,444,161	0
27	Real & Pers.Prop. 1997			4,920,000		
28						
29	Real & Pers.Prop.(FRECO)1994	(1,289)	0	1,289	0	0
30	Real & Pers.Prop.(FRECO) 1995	(811)	0	9,757	8,946	0
31	Real & Pers.Prop.(FRECO)1996		0	30,200	29,126	
32						
33	STATE OF INDIANA					
34	Taxes on Income		0	0	0	0
35						
36	STATE OF WEST VIRGINIA					
37	Taxes on Income	0	0	265		0
	Business Franchise Tax-1995	(42)	0	132	90	0
40	Business Franchise Tax-1996	0	0	0	(90)	0
	OTAL	$7,972,012	$193,143	$14,144,432	$17,025,655	0

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

. If any tax (exclude Federal and State income taxes) ers more than 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 footnote. 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 we distributed. Report in column (i) only the amounts charged Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show 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				
(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)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
(879,417)	0	5,118,476	0	0	(473,600)	2
						3
0	0	0	0	0	(2,124)	4
2,741	0	34,417	0	0	13,627	5
						6
0	0	0	0	0	(34,390)	7
67,706	0	1,782,194	0	0	1,052,507	8
						9
0	0	0	0	0	(2,409)	10
(9,032)	0	23,591	0	0	2,409	11
						.
(478,187)	0	709,594		0	352,947	14
		25				15
0	166,536	359,648	0	0	0	16
						17
0	0	0	0	0	(1,021)	18
1,347	0	20,203	0	0	6,813	19
						20
0	0	0	0	0	0	21
						22
61,356	0	0	0	0	0	23
0	0	55,357				24
75,000	0	100,548	0	0	22,577	25
1,301,239	0	4,704,000	0	0	(4,662,600)	26
4,920,000					4,920,000	27
						28
0	0	0	0	0	1,289	29
0	0	0	0	0	9,757	30
1,074	0	0			30,200	31
						32
						33
0	0	0	0	0	0	34
						35
						36
265	0	144	0	0	121	-
0	0	132	0	0	0	39
90	0	0	0	0	0	40
$5,064,182	$166,536	$12,908,329	0	0	$1,236,103	41

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KENTUCKY POWER COMPANY

DETAIL OF COLUMN L. PAGE 263

Line	TOTAL	408.2 & 409.2	ACCT. DISTR. EMPLOYMENT TAXES*	PROPERTY TAXES*	OTHER
2	(473,600)	(473,600)			
4	(2,124)		(2,124)		
5	13,627		13,627		
7	(34,390)		(34,390)		
8	1,052,507		1,052,507		
10	(2,409)	(2,409)			
11	2,409	2,409			
14	352,947	(111,634)			464,581
18	(1,021)		(1,021)		
19	6,813		6,813		
25	22,577				22,577
26	(4,662,600)			(4,704,000)	41,400
27	4,920,000			4,920,000	
29	1,289	1,289			
30	9,757	9,757			
31	30,200	30,200			
37	121				121
41	1,236,103	(543,988)	1,035,412	216,000	528,679

*DISTRIBUTION OF EMPLOYMENT TAXES

ACCOUNT	AMOUNT
107	641,955
108	62,125
152	82,833
163	103,541
184	51,771
186	93,187
	1,035,412

#DISTRIBUTION OF PROPERTY TAXES

ACCOUNT	AMOUNT
186	216,000

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Footnote - Item #1 - Federal and State Taxes are included with material cost and are estimated as follows:

Federal Gasoline Tax	78,000
State of Kentucky Gasoline Tax	51,000
State of Kentucky Auto License & Usage	44,947
State of Kentucky Highway Use Tax	516,680
State of Kentucky Highway Use & Fuel Tax	3,850
Federal Highway Use Tax	2,200
	696,677

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	1,558,178			411.4	146,788	* (10,459)
4	7%						
5	10%	16,838,737			411.4	1,085,552	* (146,992)
6							
7							
8	TOTAL	$18,396,915		0		$1,232,340	($157,451)
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
24							
25							
26							
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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.
[redacted]	[redacted]		1
0			2
1,400,931	30 Yrs.		3
0			4
15,606,193	30 Yrs.		5
0			6
0			7
$17,007,124			8
[redacted]			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
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KENTUCKY POWER COMPANY

Adjustment of Prior Years Federal Income Tax Returns
Acct. 411.5 ($10,459)

< Page 266 Line 5 Column G >

Adjustment of Prior Years Federal Income Tax Return
Account 411.5 ($146,992)

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OTHER DEFERRED 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 of Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Wintercare-Customer Donations					
2		$121	VAR	$3,097	$4,031	$1,055
3	Lessee Rent Prepayments -					
4	FRECO Property					
5		1,957	418	300		1,657
6			421	3,856		(3,856)
7			454	2,656		(2,656)
8			VAR	4,005	10,070	6,065
9	Unclassified OTC Payments					
10		940	131	832	4	112
11	Unclaimed Checks					
12		0	VAR	4,036	3,886	(150)
13	E-LAMP investment					
14		28,000	155	28,000		0
15	Nature Conservatory					
16		0	401		53,550	53,550
17						
18						
20						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
40						
41						
42						
43						
46						
47	TOTAL	$31,018		$46,782	$71,541	$55,777

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

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

Line No.	Account Subdivisions (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	$74,333,599	$5,702,451	$3,461,328
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)	$74,333,599	$5,702,451	$3,461,328
6	Other (Specify) Accum.DFIT-Other Property	17,914		
7	SFAS 109	40,249,040		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$114,600,553	$5,702,451	$3,461,328
10	Classification of TOTAL			
11	Federal Income Tax	114,600,553	5,702,451	3,461,328
12	State Income Tax			
13	Local Income Tax			

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

income and deductions.

. 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)	
[redacted]							1
						$76,574,722	2
						0	3
						0	4
0	0		0		0	$76,574,722	5
						17,914	6
				182/254	654,989	40,904,029	7
						0	8
0	0		0		$654,989	$117,496,665	9
[redacted]							10
					654,989	117,496,665	11
						0	12
						0	13

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ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

. Report the information called for below concerning the ›espondent's accounting for deferred income taxes relating to amounts recorded in Account 283.

2. For Other (Specify), include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	$33,472	$1,220,774	$1,173,612
4	Clearing Accounts	159,583	912,130	979,115
5	Post Retirement Benefits	180,890	0	180,882
6	Loss on Reacquisition of Debt	248,282	100,137	42,042
7	Emission Allowances	0	82,453	25,383
8	Other	14,616	0	14,616
9	TOTAL Electric (Total of lines 3 thru 8)	$636,843	$2,315,494	$2,415,650
10	Gas			
11		0		
12		0		
13		0		
14		0		
15		0		
16	Other	0		
17	TOTAL Gas (Total of lines 11 thru 16)	0	0	0
18	Other (Specify) SFAS 109	59,420,290	0	0
10	TOTAL (Acct 283) (Enter Total of lines 9,17 and 18)	$60,057,133	$2,315,494	$2,415,650
	Classification of TOTAL			
21	Federal Income Tax	34,570,133	2,315,494	2,415,650
22	State Income Tax	25,487,000		
23	Local Income Tax	0		

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

income and deductions.

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 Credits 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
							2
						$80,634	3
						92,598	4
						8	5
						306,377	6
						57,070	7
						0	8
0	0		0		0	$536,687	9
[redacted]							10
						0	11
						0	12
						0	13
						0	14
						0	15
						0	16
0	0		0		0	0	17
				182/254	7,002,777	66,423,067	18
0	0		0		$7,002,777	$66,959,754	19
[redacted]							20
					1,778,777	36,248,754	21
					5,224,000	30,711,000	22
						0	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 ratemaking 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 (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	SFAS 109 Deferred Federal Income Taxes	190	$748,357	0	$9,157,677
2					
3	Excess of Base Fuel Cost Deferred-Credit	401		366,564	1,097,364
4					
5	Excess of Base Fuel Cost Deferred-				
6	Accrued Utility Revenues Credit	401	327,303	467,647	44,709
7					
8	SFAS 109 Excess Deferred Federal Income Taxes -				
9	Credit	VAR	823,591	0	8,638,812
10					
11	Proceeds From Allowance Auctions Received	VAR	139,762		0
12					
13	Carrying Charges on Allowance Gains/	VAR	12,547		
14	Interim FERC				0
15					
16					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41	TOTAL		$2,051,560	$834,211	$18,938,562

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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	$106,441,290	$107,546,299
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	58,416,959	58,606,242
5	Large (or Ind.) (See Instr.4)	92,322,561	96,647,208
6	(444) Public Street and Highway Lighting	845,597	846,645
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	$258,026,407	$263,646,394
11	(447) Sales for Resale	$57,140,792	$60,567,141
12	TOTAL Sales of Electricity	* $315,167,199	$324,213,535
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	$315,167,199	$324,213,535
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$1,410,848	$1,170,152
17	(451) Miscellaneous Service Revenues	113,552	92,380
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	735,901	721,213
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	5,893,376	1,946,600
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$8,153,677	$3,930,345
27	TOTAL Electric Operating Revenues	$323,320,876	$328,143,880

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ELECTRIC OPERATING REVENUES (Account 400)(Continued)

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 increases 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		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
2,190,616	2,191,986	140,844	139,393	2
				3
1,150,454	1,134,509	23,048	22,659	4
3,076,374	2,980,230	1,711	1,754	5
9,909	10,082	467	464	6
				7
				8
				9
6,427,353	6,316,807	166,070	164,270	10
3,680,301	4,025,677	57	31	11
10,107,654	10,342,484	166,127	164,301	12
				13
10,107,654	10,342,484	166,127	164,301	14

Line 12, Column (b) includes $ (5,325,102) of unbilled revenues.

Line 12, Column (d) includes (69,349) MWH relating to unbilled revenues.

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< Page 300 Line 12 Column B >

KENTUCKY POWER COMPANY

Unmetered Sales Included in Service:

	440	442	444
Customers	31,845	5,541	24
Revenue	2,086,640	818,282	5,846
MWH Sales (Est)	20,151	9,257	42

Page 300-301 Footnote.1

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	12/31/96	Dec. 31, 1996

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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," pages 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	2,216,099	106,493,377	140,642	15,757	4.8054¢
3	RS-LM-TOD	6,540	219,699	200	32,700	3.3593¢
4	RS-TOD	35	1,171	1	35,000	3.3457¢
5	OL	20,151	2,086,640 *			10.3550¢
6	SGS	(1)	(61)	1	(1,000)	6.1000¢
7	UNBILLED REVENUE	(52,208)	(2,359,536)			4.5194¢
8	TOTAL RESIDENTIAL	2,190,616	106,441,290	140,844	15,553	4.8589¢
9						
10	442 - COMMERCIAL AND INDUSTRIAL					
11	SGS	60,992	4,531,742	13,143	4,640	7.4300¢
12	MGS	564,330	32,042,305	10,651	52,983	5.6779¢
	MGS-TOD	925	48,373	31	29,838	5.2295¢
	LGS	787,521	34,577,457	819	961,564	4.3906¢
	LGS-LM-TOD	2,117	74,578	6	352,833	3.5228¢
	IRP	145,987	4,063,900	1	145,987,000	2.7837¢
17	QP	845,728	28,338,239	68	12,437,176	3.3507¢
18	CIP-TOD	1,814,465	48,674,547	11	164,951,363	2.6825¢
19	MW	12,446	527,476	29	429,172	4.2381¢
20	OL	9,257	818,282			8.8396¢
21	UNBILLED REVENUE	(16,940)	(2,957,379)			17.4579¢
22	TOTAL COMMERCIAL AND INDUSTRIAL	4,226,828	150,739,520	24,759	170,718	3.5662¢
23						
24	444-PUBLIC ST. & HWY. LIGHTING					
25	SGS	1,901	142,765	396	4,800	7.5099¢
26	MGS	549	31,981	15	36,600	5.8253¢
27	SL	7,469	668,587	56	133,375	8.9514¢
28	OL	42	5,846			13.9190¢
29	UNBILLED REVENUE	(52)	(3,582)			6.8884¢
30	TOTAL PUBLIC ST. & HWY. LIGHTING	9,909	845,597	467	21,218	8.5336¢
31						
32						
33						
34						
35						
36						
37						
38						
	Total Billed	6,496,553	$263,346,904	166,070	39,119	4.0536¢
42	Total Unbilled Rev.(See Instr. 6)	(69,200)	($5,320,497)			7.6885¢
	TOTAL	6,427,353	$258,026,407	166,070	38,702	4.0145¢

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< Page 304 Line 5 Column D >

KENTUCKY POWER COMPANY

INSTRUCTION #3

Average number of OL customers not included in total - 37,410

INSTRUCTION #5

Amount of Fuel Adjustment Clause Included in Rate:

Residential	RS	352,383
Residential	RS-LM-TOD	590
Residential	RS-TOD	2
Small General Service	SGS	(1,855)
Medium General Service	MGS	(9,674)
MGS - Time-of-Day	MGS-TOD	(70)
Large General Service	LGS	(12,221)
LGS-Load Management-TOD	LGS-LM-TOD	(7)
Outdoor Lights	OL	(4,866)
Quantity Power	QP	(55,765)
Street Lighting	SL	(1,053)
Mun. Waterworks	MW	84
Interruptible Power	IRP	(24,765)
Commercial & Ind.-Time-of-Day	CIP-TOD	(255,210)
TOTAL		(12,427)

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(Next page is 310)

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for long-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 seller 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 desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Hamilton	RQ	OPCo 96	0	0	0
2	City of Olive Hill	RQ	KPCo 13	5.1	5.1	5.1
3	City of Vanceburg	RQ	KPCo 18	10.4	10.4	10.4
4	SUBTOTAL-RQ					
5						
6	Carolina P&L	LU	APCo 24	N/A	N/A	N/A
7	VEPCo	LU	APCO 16	N/A	N/A	N/A
8						
9	City of Dover	SF	OPCo 74	N/A	N/A	N/A
10	AMP Ohio	SF	OPCo 74	N/A	N/A	N/A
11	City of St. Marys	SF	OPCo 74	N/A	N/A	N/A
12	City of Shelby	SF	OPCo 74	N/A	N/A	N/A
13	City of Columbus	SF	OPCo 74	N/A	N/A	N/A
14	Edison Sault Elec	SF	* Note(1)	N/A	N/A	N/A

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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) 12/31/96	Year of Report Dec. 31, 1996

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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 exptanations following all required data.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
0	0	0	$5,400	$5,400	1
27,292	546,983	349,078	2,040	898,101	2
55,188	912,202	683,751	13,320	1,609,273	3
82,480	1,459,185	1,032,829	20,760	2,512,774	4
					5
0			* 470,688	470,688	6
10,604	197,506	584,197	657,802	1,439,505	7
					8
313	6,085	14,798	5,133	26,016	9
12,447	125,066	177,415	42,262	344,743	10
597	4,300	4,382	4,970	13,652	11
0	869	1,356	804	3,029	12
0	3,328	3,063	3,416	9,807	13
8,784	26,631	181,823	25,446	233,900	14

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

LF - for long-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 seller 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 desgnated 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	Cleveland Pub Pwr	SF	Note (1)	N/A	N/A	N/A
2						
3	Indianapolis P&L	LF	IMPCo 21	N/A	N/A	N/A
4	NCEMC	LF	APCO 135	N/A	N/A	N/A
5	AMP Ohio	LF	OPCo 74	N/A	N/A	N/A
6	City of Columbus	LF	OPCo 74	N/A	N/A	N/A
7	City of Dover	LF	OPCO 74	N/A	N/A	N/A
8	City of St. Marys	LF	OPCo 74	N/A	N/A	N/A
9						
10	Indianapolis P&L	IF	IMPCo 21	N/A	N/A	N/A
11						
12	AEP AFF - Assoc Co	OS	APCO 20	N/A	N/A	N/A
13	AIG Trading Group	OS	Note (1)	N/A	N/A	N/A
14	AES Power, Inc	OS	Note (1)	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

	REVENUE				
Megawatthours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
2,524	$34,686	$56,837	$17,747	$109,270	1
					2
11,441	666,653	169,286	294,738	1,130,677	3
122,826	860,620	1,686,684	288,647	2,835,951	4
32,966	552,467	469,812	100,671	1,122,950	5
15,321	224,442	203,560	39,777	467,779	6
0	14,962	11,380	2,652	28,994	7
0	22,445	20,445	3,978	46,868	8
				0	9
1,185		16,479	0	16,479	10
				0	11
2,293,895		27,968,782	0	27,968,782	12
10		408	55	463	13
589		2,948	532	3,480	14

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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:

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LF - for long-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 seller can unilaterally get out of the contract.

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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	ALPENA Power Co	OS	Note (1)	N/A	N/A	N/A
2	AMP Ohio	OS	OPCo 74	N/A	N/A	N/A
3	AQUILA Power Corp	OS	Note (1)	N/A	N/A	N/A
4	AYP Energy	OS	Note (1)	N/A	N/A	N/A
5	Carolina P & L	OS	APCo 24	N/A	N/A	N/A
6	CATEX-VITOL Elec	OS	Note (1)	N/A	N/A	N/A
7	Central ILL PS	OS	IMPCo 67	N/A	N/A	N/A
8	Cincinnati G&E	OS	OPCo 21	N/A	N/A	N/A
9	Citizens-Lehman Power	OS	Note (1)	N/A	N/A	N/A
10	City of Cleveland	OS	Note (1)	N/A	N/A	N/A
11	City of Columbus	OS	OPCo 74	N/A	N/A	N/A
12	Cleveland Elec Illum	OS	OPCo 31	N/A	N/A	N/A
13	CNG Energy Serv	OS	Note (1)	N/A	N/A	N/A
14	COASTAL Elec Services	OS	Note (1)	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
4,038		$77,274	$37,998	$115,272	1
18,541		346,008	61,830	407,838	2
1,310		32,341	3,119	35,460	3
51		2,068	294	2,362	4
8,240		184,351	26,391	210,742	5
4,241		99,329	9,222	108,551	6
3,742		96,669	5,260	101,929	7
2,544		73,686	10,329	84,015	8
2,862		60,738	6,050	66,788	9
4,327		54,374	5,531	59,905	10
1,806		43,473	8,023	51,496	11
905		31,744	3,813	35,557	12
646		13,330	1,580	14,910	13
84		1,235	264	1,499	14

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for long-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 seller 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 desgnated 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	Commonweatlh Edison	OS	IMPCo 20	N/A	N/A	N/A
2	Consumers Power	OS	IMPCo 68	N/A	N/A	N/A
3	Coral Power	OS	Note (1)	N/A	N/A	N/A
4	Dayton P.	OS	OPCo 36	N/A	N/A	N/A
5	Delhi Energy Serv	OS	NOte (1)	N/A	N/A	N/A
6	City of Dover	OS	OPCo 74	N/A	N/A	N/A
7	Duke	OS	APCo 18	N/A	N/A	N/A
8	Duquesne	OS	OPCo 33	N/A	N/A	N/A
9	Eastex Pwr Mkt	OS	Note (1)	N/A	N/A	N/A
10	EKPCC	OS	KPCo 14	N/A	N/A	N/A
11	Electric Clearing House	OS	Note (1)	N/A	N/A	N/A
12	Engelhard Pwr Mkt	OS	Note (1)	N/A	N/A	N/A
13	Enron Pwr Mkt	OS	Note (1)	N/A	N/A	N/A
14	Entergy	OS	Note (1)	N/A	N/A	N/A

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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) 12/31/96	Year of Report Dec. 31, 1996

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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 exptanations following all required data.

	REVENUE				
Megawatthours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
70,078		$1,753,565	$232,102	$1,985,667	1
100,540		1,976,456	317,996	2,294,452	2
394		10,279	1,941	12,220	3
2,129		53,606	6,647	60,253	4
405		11,901	1,877	13,778	5
512		13,176	1,320	14,496	6
27,843		559,687	79,658	639,345	7
5,084		105,177	8,863	114,040	8
569		32,732	1,601	34,333	9
4,315		123,342	13,442	136,784	10
1,367		31,891	4,700	36,591	11
14		236	50	286	12
14,503		248,884	33,365	282,249	13
878		26,245	3,079	29,324	14

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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) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for long-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 seller 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 desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line	Name of Company or Public Authority [Footnote Affiliations] (a)	Statis-tical Classifi-cation (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)	N/A	N/A	N/A
2	Heartland Eng Serv	OS	Note (1)	N/A	N/A	N/A
3	Illinois Power	OS	IMPCo 23	N/A	N/A	N/A
4	IMPA	OS	IMPCo 74	N/A	N/A	N/A
5	Indianapolis P&L	OS	IMPCo 21	N/A	N/A	N/A
6	Kentucky Utilities	OS	OPCo 22	N/A	N/A	N/A
7	KOCH Power Serv	OS	Note (1)	N/A	N/A	N/A
8	LG&E	OS	Note (1)	N/A	N/A	N/A
9	Louis Dreyfus Elec Pwr	OS	NOte (1)	N/A	N/A	N/A
10	Louisville Gas & Elec	OS	IMPCo 79	N/A	N/A	N/A
11	Mich Pub Pwr Agency	OS	Note (1)	N/A	N/A	N/A
12	Mid Con Pwr Serv	OS	Note (1)	N/A	N/A	N/A
13	Morgan Stanley Group	OS	Note (1)	N/A	N/A	N/A
14	NIPSCo	OS	IMPCo 22	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
4,276		$97,248	$17,262	$114,510	1
1,513		30,680	1,641	32,321	2
4,958		132,922	17,362	150,284	3
12,965		254,904	48,231	303,135	4
199		4,057	370	4,427	5
57		1,470	182	1,652	6
12,445		308,541	41,396	349,937	7
14,340		265,571	53,260	318,831	8
12,840		223,435	52,480	275,915	9
901		30,118	3,791	33,909	10
13,708		242,654	24,619	267,273	11
0		740	121	861	12
80		2,035	0	2,035	13
2,543		79,401	11,050	90,451	14

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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:

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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	NORAM Energy Serv	OS	Note (1)	N/A	N/A	N/A
2	Ohio Edison	OS	OPCo 25	N/A	N/A	N/A
3	Orrville	OS	OPCo 74	N/A	N/A	N/A
4	OVEC	OS	APCo 22	N/A	N/A	N/A
5	Pan Energy	OS	Note (1)	N/A	N/A	N/A
6	PECO Energy, Inc.	OS	Note (1)	N/A	N/A	N/A
7	PHIBRO, Inc.	OS	Note (1)	N/A	N/A	N/A
8	Pennsylvania P&L	OS	Note (1)	N/A	N/A	N/A
9	Power Co. of America	OS	Note (1)	N/A	N/A	N/A
10	PS of Indiana	OS	IMPCo 24	N/A	N/A	N/A
11	Rainbow Energy Mkt	OS	Note (1)	N/A	N/A	N/A
12	Richmond P&L	OS	IMPCo 70	N/A	N/A	N/A
13	SCANA Enery Mkt	OS	Note (1)	N/A	N/A	N/A
14	Shelby	OS	OPCo 74	N/A	N/A	N/A

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SALES FOR RESALE (Account 447) (Continued)

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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) 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 megawatthours 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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	REVENUE				
Megawatthours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
1,130		$24,495	$4,093	$28,588	1
19,328		460,235	32,493	492,728	2
388		7,103	454	7,557	3
878		78,729	30,513	109,242	4
89		2,253	333	2,586	5
151,519		2,686,577	436,313	3,122,890	6
5,001		83,135	3,773	86,908	7
19		304	55	359	8
45		1,903	227	2,130	9
2,158		66,347	5,796	72,143	10
4,383		106,804	7,577	114,381	11
5,762		105,956	15,488	121,444	12
112		2,689	323	3,012	13
94		20,455	1,755	22,210	14

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Line	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	SONAT Pwr Mkt	OS	Note (1)	N/A	N/A	N/A
2	Southern Engy Mkt	OS	Note (1)	N/A	N/A	N/A
3	St. Mary	OS	OPCo 74	N/A	N/A	N/A
4	Trans Canada Pwr	OS	Note (1)	N/A	N/A	N/A
5	Toledo Ed	OS	OPCo 35	N/A	N/A	N/A
6	TVA	OS	APCo 52	N/A	N/A	N/A
7	VEPCo	OS	APCo 16	N/A	N/A	N/A
8	Wabash Valley Power	OS	IMPCo 76	N/A	N/A	N/A
9	Wisconsin Elec Pwr	OS	Note (1)	N/A	N/A	N/A
10	Western Pwr Serv	OS	Note (1)	N/A	N/A	N/A
11	West Penn Pwr	OS	OPCo 73	N/A	N/A	N/A
12	Wisconsin Power	OS	Note(1)	N/A	N/A	N/A
13						
14	AES Power	OS	Note (1)	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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 exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
1,940		$44,624	$6,837	$51,461	1
3,224		49,169	7,242	56,411	2
2,950		49,759	4,827	54,586	3
64		1,203	160	1,363	4
1,579		37,307	5,854	43,161	5
38,269		974,020	128,229	1,102,249	6
13,208		267,269	21,651	288,920	7
452		12,519	34	12,553	8
540		14,604	1,358	15,962	9
240		6,848	952	7,800	10
11,785		211,358	21,478	232,836	11
1,462		41,519	3,114	44,633	12
					13
175,534	0		* 1,392,454	1,392,454	14

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

LF - for long-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 seller 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 desgnated 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	Carolina P&L	OS	Note (1)	N/A	N/A	N/A
2	CATEX-VITOL Elec	OS	Note (1)	N/A	N/A	N/A
3	Citizens-Lehman Pwr	OS	Note (1)	N/A	N/A	N/A
4	Koch Power Serv	OS	Note (1)	N/A	N/A	N/A
5	PECo Energy, Inc	OS	Note (1)	N/A	N/A	N/A
6	PHIBRO, Inc	OS	Note (1)	N/A	N/A	N/A
7						
8	SUBTOTAL-NON-RQ					
9						
10	TOTAL					
11						
12						
13						
14						

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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 exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
41,921			$149,879	$149,879	1
2,295			22,030	22,030	2
84,930			643,252	643,252	3
92,761			751,659	751,659	4
8,799			64,758	64,758	5
48,667			337,157	337,157	6
					7
3,597,821	2,740,060	44,668,412	7,219,546	54,628,018	8
					9
3,680,301	4,199,245	45,701,241	7,240,306	57,140,792	10
					11
					12
					13
					14

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< Page 310 Line 14 Column c >

note (1) - AEP Power Sales Tariff, AEP companies FERC Electric Tariff Original Volume 2

< Page 311 Line 6 Column j >

Amounts in Column J, Page 311, Line 6 thru Page 311.6 Line 12 Represent Transmission Charges Associated with Account 447.

< Page 311.6 Line 14 Column j >

Amounts in Column J, Page 311.6 line 14 thru 311.7 line 6 represents coal conversion services and related transmission charges.

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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	$2,572,976	$1,922,504
5	(501) Fuel	* 67,697,233	80,336,820
6	(502) Steam Expenses	2,745,938	1,874,757
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred--Cr.		
9	(505) Electric Expenses	214,104	784,123
10	(506) Miscellaneous Steam Power Expenses	2,055,334	2,141,333
11	(507) Rents	9,945	8,604
12	(509) Allowance	(264,640)	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$75,030,890	$87,068,141
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$2,315,536	$1,479,666
16	(511) Maintenance of Structures	1,639,879	903,853
17	(512) Maintenance of Boiler Plant	11,649,423	7,929,911
18	(513) Maintenance of Electric Plant	2,200,845	2,045,764
19	(514) Maintenance of Miscellaneous Steam Plant	828,591	705,948
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$18,634,274	$13,065,142
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$93,665,164	$100,133,283
22	B. Nuclear Power Generation		
	Operation		
	(517) Operation Supervision and Engineering		
	(518) Fuel		
	(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--Nuclear Power (Enter total of lines 33 and 40)	0	0
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		
	(540) Rents		
	TOTAL Operation (Enter Total of lines 44 thru 49)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

	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(Enter total of lines 50 and 58)	0	0
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 Total of lines 67 and 73)	0	0
	E. Other Power Supply Expenses		
	(555) Purchased Power	$96,484,586	$88,472,185
	(556) System Control and Load Dispatching	887,882	819,897
78	(557) Other Expenses	76	2,345
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$97,372,544	$89,294,427
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$191,037,708	$189,427,710
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$1,045,683	$613,130
84	(561) Load Dispatching	233,223	299,278
85	(562) Station Expenses	232,250	276,646
86	(563) Overhead Lines Expenses	183,002	255,097
87	(564) Underground Lines Expenses	0	0
88	(565) Transmission of Electricity by Others	(3,041,968)	(3,482,428)
89	(566) Miscellaneous Transmission Expenses	751,170	724,999
90	(567) Rents	1,729	8,049
91	TOTAL Operation (Enter Total of lines 83 thru 90)	($594,911)	($1,305,229)
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$233,318	$324,089
94	(569) Maintenance of Structures	42,957	29,797
95	(570) Maintenance of Station Equipment	1,143,491	964,051
96	(571) Maintenance of Overhead Lines	858,521	829,654
97	(572) Maintenance of Underground Lines	0	57
98	(573) Maintenance of Miscellaneous Transmission Plant	52,414	(7,358)
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$2,330,701	$2,140,290
	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$1,735,790	$835,061
	3. DISTRIBUTION EXPENSES		
102	Operation		
	(580) Operation Supervision and Engineering	$1,180,294	$1,226,402

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount For Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	$129,644	$3,917
106	(582) Station Expenses	196,527	187,389
107	(583) Overhead Line Expenses	290,801	266,706
108	(584) Underground Line Expenses	13,832	5,451
109	(585) Street Lighting and Signal System Expenses	43,851	58,335
110	(586) Meter Expenses	993,478	1,001,506
111	(587) Customer Installations Expenses	312,126	408,054
112	(588) Miscellaneous Expenses	2,606,434	3,793,843
113	(589) Rents	369,568	446,503
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$6,136,555	$7,398,106
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$523,491	$791,410
117	(591) Maintenance of Structures	48,502	16,294
118	(592) Maintenance of Station Equipment	562,259	442,92[illegible]
119	(593) Maintenance of Overhead Lines	7,584,978	8,339,8[illegible]
120	(594) Maintenance of Underground Lines	132,218	151,21[illegible]
121	(595) Maintenance of Line Transformers	845,170	950,969
122	(596) Maintenance of Street Lighting and Signal Systems	144,362	69,287
123	(597) Maintenance of Meters	243,632	274,494
124	(598) Maintenance of Miscellaneous Distribution Plant	232,475	251,037
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$10,317,087	$11,287,510
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$16,453,642	$18,685,616
	4.CUSTOMER ACCOUNTS EXPENSES		
	Operation		
	(901) Supervision	$476,997	$324,026
130	(902) Meter Reading Expenses	1,617,851	1,849,387
131	(903) Customer Records and Collection Expenses	4,345,986	3,323,094
132	(904) Uncollectible Accounts	1,507,734	925,000
133	Miscellaneous Customer Accounts Expenses	405,100	645,720
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$8,353,668	$7,067,227
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$388,983	$792,603
138	(908) Customer Assistance Expenses	3,290,795	1,061,609
139	(909) Information and Instructional Expenses	40,331	164,106
140	(910) Miscellaneous Customer Service and Information Expenses	1,061,725	313,737
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$4,781,834	$2,332,055
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	3,261	5,370
146	(913) Advertising Expenses	112,651	99,895
147	(916) Miscellaneous Sales Expenses	419,786	455,922
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$535,698	$561,187
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$4,503,868	$7,550,016
152	(921) Office Supplies and Expenses	4,452,493	3,876,841
	(Less) (922) Administrative Expenses Transferred--Credit	128	146,949

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$559,931	$131,258
156	(924) Property Insurance	299,471	235,573
157	(925) Injuries and Damages	2,814,495	1,521,407
158	(926) Employee Pensions and Benefits	6,946,867	6,678,638
159	(927) Franchise Requirements	117,020	117,167
160	(928) Regulatory Commission Expenses	296,567	377,139
161	(929) (Less) Duplicate Charges--Cr.		
162	(930.1) General Advertising Expenses	* 151,974	385,868
163	(930.2) Miscellaneous General Expenses	973,170	882,663
164	(931) Rents	1,721	35,925
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$21,117,449	$21,645,546
166	Maintenance		
167	(935) Maintenance of General Plant	$1,510,948	$1,383,669
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$22,628,397	$23,029,215
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	$245,526,737	$241,938,071

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 personel, include such employees 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 dete mined 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)	12/31/96	
2. Total Regular Full-Time Employees		717
3. Total Part-Time and Temporary Employees		1
4. Total Employees		718

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< Page 320 Line 2 Column B >

KENTUCKY POWER COMPANY

ACCOUNT 50199

Includes a debit pertaining to the Deferred Fuel Costs of $683,350 applicable to current year.

< Page 323 Line 162 Column 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 1996 $130,757 was related to advertising as usually defined and $21,217 was related to other activities.

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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) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP Generating Co. (3)	RQ	AEG 1	N/A	N/A	N/A
2			(2)			
3	West Penn Power/Allegheny Power	SF	OPCO 73			
4						
5	Indianapolis Power & Light	IF	IMPCO 21	N/A	N/A	N/A
6						
7	Tennessee Valley Authority	OS	APCO 52	N/A	N/A	N/A
8	Carolina Power & Light	OS	APCO 24	N/A	N/A	N/A
9	Duke Power Co.	OS	APCO 18	N/A	N/A	N/A
10	Virginia Electric & Power	OS	APCO 16	N/A	N/A	N/A
11	PECO Energy	OS	(4)	N/A	N/A	N/A
12	Commonwealth Edison Co.	OS	IMPCO 20	N/A	N/A	N/A
13	Northern Indiana Pub. Serv. Co.	OS	IMPCO 22	N/A	N/A	N/A
14	Public Service of Indiana	OS	IMPCO 24	N/A	N/A	N/A

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,505,898			$9,634	$67,365,089		$67,374,723	1
							2
910				5,943		5,943	3
							4
111				3,211		3,211	5
						0	6
15,626				363,537		363,537	7
3,729				105,411		105,411	8
3,402				134,099		134,099	9
5,735				199,198		199,198	10
20,443				392,991		392,991	11
14,839				116,164		116,164	12
461				10,487		10,487	13
988				34,496		34,496	14

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PURCHASED POWER (Account 555)
(Including power exchanges)

. Report all power purchases made during the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

ine No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand	Actual Demand(MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Illinois Power Co.	OS	IMPCO 23	N/A	N/A	N/A
2	Indianapolis Power & Light	OS	IMPCO 21	N/A	N/A	N/A
3	Toledo Edison Co.	OS	OPCO 35	N/A	N/A	N/A
4	Ohio Edison	OS	OPCO 25	N/A	N/A	N/A
5	Clevelar Elec. Illuminating Co.	OS	OPCO 31	N/A	N/A	N/A
6	Daytor wer & Light Co.	OS	OPCO 36	N/A	N/A	N/A
7	Duque:	OS	OPCO 33	N/A	N/A	N/A
8	Kentucky Utilities	OS	OPCO 22	N/A	N/A	N/A
9	Cincinnati Gas & Electric Co.	OS	OPCO 21	N/A	N/A	N/A
!0	West Penn Power/Allegheny Power	OS	OPCO 73	N/A	N/A	N/A
.1	Central Illinois Public Serv.	OS	IMPCO 67	N/A	N/A	N/A
2	Consumers Power Co.	OS	IMPCO 68	N/A	N/A	N/A
3	Louisville Gas & Electric	OS	IMPCO 70	N/A	N/A	N/A
4	Richmond Power & Light Co.	OS	IMPCO 70	N/A	N/A	N/A

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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) 12/31/96	Year of Report Dec. 31, 1996

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
478				$12,314		$12,314	1
803				15,269		15,269	2
156				4,068		4,068	3
756				16,658		16,658	4
3,749				65,043		65,043	5
2,162				41,616		41,616	6
510				12,530		12,530	7
156				2,933		2,933	8
207				4,948		4,948	9
2,910				83,176		83,176	10
2,320				109,747		109,747	11
32,782				1,055,369		1,055,369	12
5,928				119,740		119,740	13
20				1,245		1,245	14

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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) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Columbus	OS	OPCO 74	N/A	N/A	N/A
2	Wisconsin Power and Light	OS	(4)	N/A	N/A	N/A
3	Cinergy Services, Inc.	OS	(4)	N/A	N/A	N/A
4	PJM	OS	(4)	N/A	N/A	N/A
5	AEP System Power Pool (5)	OS	IMPCO 17	N/A	N/A	N/A
6						
7	City of St. Marys (6)	AD	OPCO 74	N/A	N/A	N/A
8	American Municipal Power (6)	AD	OPCO 74	N/A	N/A	N/A
9	City of Hamilton (6)	AD	OPCO 74	N/A	N/A	N/A
10	City of Dover (6)	AD	OPCO 74	N/A	N/A	N/A
11	City of Shelby (6)	AD	OPCO 74	N/A	N/A	N/A
12	East Kentucky Power Coop	AD	KPCO 14	N/A	N/A	N/A
13						
14	Loop Regulation Energy					

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1				$240		$240	1
64				1,711		1,711	2
122				5,317		5,317	3
1,033				28,441		28,441	4
1,882,048				26,166,260		26,166,260	5
							6
0				338		338	7
0				42		42	8
0				(13)		(13)	9
0				54		54	10
0				45		45	11
0				(23)		(23)	12
							13
(899)				(2,472)		(2,472)	14

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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) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report ›ower purchases made during the year. lso report anges of electricity (i.e. transactions involvin. 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 - fr requirements service. Requirements service is se which the supplier plans to provide on an ongoir sis(i.e., the supplier includes projected load fo. 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Misc. Adjustments to MWH (7)					
2						
3						
4	TOTAL					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
19,655							1
							2
							3
4,527,103	0	0	9,634	96,475,222	0	96,484,856	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14

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< Page 326 Line 4 Column B >

KENTUCKY POWER COMPANY

NOTES:

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

(2) The Respondent, Appalachian Power Company, Ohio Power Company, Indiana Michigan Power Company and Columbus Southern Power Company are associated companies and members of the American Electric Power System 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

(3) An associated company.

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

(5) 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.

(6) Adjustment for service rendered in prior period.

(7)

Loop regulation energy difference	(244)
Non-displacement payback losses	213
Purchased Power transfer losses	11,278
Unit power losses (net)	8,098
AEP System Power Pool losses	310
TOTAL	19,655

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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 or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	East Kentucky Power Coop	East Kentucky Power Coop	East Kentucky Power Coop	LF
2	Virginia Electric & Power Co.	Ohio Power Company (Assoc.)	Virginia Electric Power Co.	LF
3	Wabash Valley Power Assn.	Various	Various	LF
4	Blue Ridge Agency	PSI Energy	Blue Ridge Agency	LF
5	AES Power, Inc.	Various	Various	OS
6	AIG Trading Corp.	Various	Various	OS
7	Alleghany Power Systems	Various	Various	OS
8	AMP-Ohio, Inc.	Various	Various	OS
9	Aquila, Inc.	Various	Various	OS
10	AYP Energy, Inc.	Various	Various	OS
11	Commonwealth Edison	Various	Various	OS
12	Cleveland Electric Illuminating	Various	Various	OS
13	Cinergy	Various	Various	OS
14	Citizen's Lehman	Various	Various	OS
15	Catex-Vitol	Various	Various	OS
16	CNG Energy Services Group	Various	Various	OS
17	Coral Power, LLC	Various	Various	OS

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

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

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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatthours Received (i)	Megawatthours Delivered (j)	Line No.
KPCo 14	Falcon, Thelma	Leon, Thelma	400	53,418	48,466	1
PCo 16	Ohio Power Company	Virginia Elec Pwr	226	168,890	165,495	2
IMPCo 76	Various	Various	41	54,809	52,782	3
Footnotes	Various	Blue Ridge		24,046	23,180	4
Footnotes	Various	Various		190	190	
See Footnote	Various	Various		300	300	
[illegible]	Various	Various		525	687	7
OPCo 74	Various	Various		56,953	55,428	8
See Footnotes	Various	Various		17,942	17,942	9
See Footnotes	Various	Various		190	190	10
IMPCo 73	Various	Various		32,363	32,304	11
OPCo 31	Various	Various		67	67	12
OPCo 21	Various	Various		56,451	56,451	13
See Footnotes	Various	Various		8,127	8,127	14
See Footnotes	Various	Various		3,688	3,686	15
See Footnotes	Various	Various		218	218	16
See Footnotes	Various	Various		295	295	17

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KPSC Case No. 99-149
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Order Dated April 22, 1999
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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) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
		$72,420	$72,420	1
		809,818	809,818	2
		364,002	364,002	3
		78,174	78,174	4
		1,366	1,366	5
		1,203	1,203	6
		366	366	7
		200,050	200,050	8
		48,681	48,681	9
		1,928	1,928	10
		128,859	128,859	11
		221	221	12
		154,540	154,540	13
		28,732	28,732	14
		10,832	10,832	15
		1,149	1,149	16
		1,269	1,269	17

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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) 12/31/96	Year of Report Dec. 31, 1996

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 or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Carolina Power & Light Company	Various	Various	OS
2	Cleveland Public Power	Various	Various	OS
3	Delhi Energy Services	Various	Various	OS
4	Dayton Power & Light	Various	Various	OS
[illegible]	[illegible] Power Co.	Various	Various	OS
[illegible]	[illegible]ic Clearinghouse, Inc.	Various	Various	OS
[illegible]	E[illegible] Kentucky Power Coop	Various	Various	OS
[illegible]	Engelhard Power Marketing, Inc.	Various	Various	OS
9	Enron Power Marketing,Inc.	Various	Various	OS
10	Federal Energy Sales	Various	Various	OS
11	Heartland Energy Services	Various	Various	OS
12	Illinova Power Marketing	Various	Various	OS
13	Indiana Municipal Power Agency	Various	Various	OS
14	IUC	Various	Various	OS
15	Koch Power Services	Various	Various	OS
16	Louisville Gas & Electric	Various	Various	OS
17	LG&E Power Marketing, Inc.	Various	Various	OS

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

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

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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megatthours Received (i)	Megatthours Delivered (j)	Line No.
APCo 24	Various	Various		480	480	1
See Footnotes	Various	Various		41,147	39,652	2
See Footnotes	Various	Various		11	11	3
[illegible] 36	Various	Various		2,061	2,061	4
[illegible] 18	Various	Various		260	260	5
[illegible] Footnotes	Various	Various		6,953	6,953	6
[illegible] 14	Various	Various		8,382	8,382	7
[illegible] Footnotes	Various	Various		614	614	8
See Footnotes	Various	Various		47,410	47,400	9
See Footnotes	Various	Various		3,595	3,366	10
See Footnotes	Various	Various		1,289	1,289	11
See Footnotes	Various	Various		146	146	12
IMPCo 74	Various	Various		33,064	31,969	13
See Footnotes	Various	Various		220	220	14
See Footnotes	Various	Various		11,812	11,816	15
See Footnotes	Various	Various		5	5	16
See Footnotes	Various	Various		4,148	4,144	17

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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) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred 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 c..umn (a). If no monetary settlement was made, enter zero ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
		$70,844	$70,844	1
		72,170	72,170	2
		36	36	3
		7,165	7,165	4
		1,202	1,202	5
		26,089	26,089	6
		34,489	34,489	7
		3,905	3,905	8
		180,816	180,816	9
		17,000	17,000	10
		4,332	4,332	11
		1,014	1,014	12
		113,529	113,529	13
		1,095	1,095	14
		51,001	51,001	15
		27	27	16
		21,099	21,099	17

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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) 12/31/96	Dec. 31, 1996

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 or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Louis Dreyfus Electric Power, Inc.	Various	Various	OS
2	MidCon Power Services Corp.	Various	Various	OS
3	Morgan Stanley & Co., Inc.	Various	Various	OS
4	Northern Indiana Public Service Co.	Various	Various	OS
	NorAm Energy Services	Various	Various	OS
	Ohio Edison	Various	Various	OS
	PAN Energy Power Services	Various	Various	OS
	Philadelphia Electric Company	Various	Various	OS
	Rainbow Energy Marketing Corp.	Various	Various	OS
10	Richmond Energy Marketing Corp.	Various	Various	OS
11	Sonat Power Marketing	Various	Various	OS
12	Stand Power Marketing	Various	Various	OS
13	Toledo Edison	Various	Various	OS
14	Virginia Electric Power	Various	Various	OS
15	Vitol Gas & Electric, LLC	Various	Various	OS
16	Western Power Services	Various	Various	OS
17	Wisconsin Power & Light	Various	Various	OS

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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) 12/31/96	Year of Report Dec. 31, 1996

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

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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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				Megatthours Received (i)	Megatthours Delivered (j)	
See Footnotes	Various	Various		4,709	4,712	1
See Footnotes	Various	Various		1,732	1,732	2
See Footnotes	Various	Various		104	104	3
IMPCo 22	Various	Various		591	591	4
[illegible] Footnotes	Various	Various		322	322	
[illegible] 25	Various	Various		349	349	
[illegible] Footnotes	Various	Various		427	427	7
See Footnotes	Various	Various		424,849	424,872	8
See Footnotes	Various	Various		4,572	4,551	9
See Footnotes	Various	Various		3,263	3,280	10
See Footnotes	Various	Various		2,964	2,964	11
See Footnotes	Various	Various		10,349	10,234	12
OPCo 35	Various	Various		94	94	13
See Footnotes	Various	Various		6,117	6,117	14
APCo 16	Various	Various		4,484	4,484	15
See Footnotes	Various	Various		150	150	16
See Footnotes	Various	Various		164	164	17

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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) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
		$17,313	$17,313	1
		5,093	5,093	2
		517	517	3
		2,369	2,369	4
		2,138	2,138	5
		978	978	6
		1,451	1,451	7
		1,527,875	1,527,875	8
		19,766	19,766	9
		13,990	13,990	10
		13,463	13,463	11
		31,015	31,015	12
		283	283	13
		20,021	20,021	14
		14,772	14,772	15
		817	817	16
		629	629	17

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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) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
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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).
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Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Cities of Bedford & Danville	Various	Various	OS
2	North Carolina Electric Membership Corp.	AEP System	See Footnotes	LF
3				
4				
	Losses Associated with Wheeling of Power			
	TOTAL			
9				
10				
11				
12				
13				
14				
15				
16				
17				

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

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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.
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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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megatthours Received (i)	Megatthours Delivered (j)	Line No.
* See Footnotes	Various	Various	6	8,275	7,979	1
See Footnotes	Various	Various				2
						3
						4
				(15,882)		5
						6
				1,097,702	1,097,702	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
		$36,761	$36,761	1
		112,938	112,938	2
				3
				4
				5
				6
0	0	4,331,612	4,331,612	7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17

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< Page 329 Line 1 Column e >

Page 329 Lines 4, 5, 6, 9, 10, 14-17 Column (e) and Column (h)

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.

Page 329.1 Lines 2, 3, 6, 8-12, 14-17 Column (e) and Column (h)

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.

Page 329.2 Lines 1, 2, 3, 5, 7-12, 14, 16-17 Cols. (e) and (h)

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.

Page 329.3 Line 1 Column (e) and Column (h)

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.

Page 328.3 and 329.3 Line 2 Column (c) and Column (e)

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.

Column (d) Earliest termination date - December 31, 2010.

Page 329.3 Line 5 Column (i) and (j)

Excludes North Carolina Electric Membership Corp., Line 1 inasmuch as these MWH are included in Account 447.

The Respondent, Columbus Southern Power Company, 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.

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

(Including transactions referred to as "wheeling")

1. : all transmission, i.e., wheeling, of elec-rici :ovided 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 provided transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.

3. Provide in column (a) subheadings and classify transmission service purchased from 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 (g) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") in column (g). Provide a footnote explaining the nature of the nonmonetary 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 losses 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.

ine o.	Name of Company or Public Authority [Footnote Affiliations] (a)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
		Megawatt-hours Received (b)	Megawatt-hours Delivered (c)	Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	AEP System Transmission						
-	Agreement (1)	*				(3,364,812)	(3,364,81
4	East KY Power Coop.					96,159	96,159
6	Virginia Power Co.	52,663	52,663	91,132			91,132
7	Duke Power Co.	52,699	52,699	135,331			135,331
8	Carolina P&L	24	24	222			222
9							
0							
1							
2							
3							
4							
5							
6	TOTAL	105,386	105,386	226,685	0	(3,268,653)	(3,041,968)

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KENTUCKY POWER COMPANY

NOTE:

(1) The respondent, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)(ELECTRIC)

Line	Description (a)	Amount (b)
1	Inc[illegible]y Association Dues	$768,173
2	Nuc[illegible] Power Research Expenses	
3	Other Experimental and General Research Expenses	17,939
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	151,400
5	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less that $5,000 by classes if the number of items so grouped is shown)	
6	Non Energy T&D Business	$5,087
7	Interest Cost on AEP Borrowed Capital	21,891
8	Load Research-Time of Day	35,918
9	AEP Serv. Corp. Federal Income Taxes & Credits	(145,857)
10	Management Development Training - general	5,993
11	Management Development Activities - general	23,026
12	Other Items (54) Under $5,000	89,600
13		
14		
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45		
46	TOTAL	$973,170

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/96	Dec. 31, 1996

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)

(Except amortization of acquisition 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 B 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 section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average 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)
[illegible]	Intangible Plant				
[illegible]	Steam Product Plant	8,637,421			8,637,421
[illegible]	Nuclear Production Plant				
[illegible]	Hydraulic Production Plant--Conventional				
5	Hydraulic Production Plant--Pumped Storage				
6	Other Production Plant				
7	Transmission Plant	4,460,292			4,460,292
8	Distribution Plant	11,069,731			11,069,731
9	General Plant	917,127			917,127
10	Common Plant--Electric				
11	TOTAL	$25,084,571			$25,084,571

B. Basis for Amortization Charges

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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	242,149			3.78%		
13	Transmission	262,199			1.71%		
14	Distribution	328,086			3.52%		*
15	General	36,492			2.54%		
16							
17							
18							
19							
20							
21							
22							
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< Page 337 Line 12 Column e >

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

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NOTE (B)

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

NOTE (C)

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

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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 accounts. 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	0
2		
3	TOTAL-425	0
4		
5	426 - OTHER INCOME DEDUCTIONS	
6		
7	426.1 DONATIONS	
8		
9	EDUCATIONAL	
10	Miscellaneous Items Under 5% of Account Total	26,450
	MEDICAL	
	Miscellaneous Items Under 5% of Account Total	760
15	COMMUNITY	
16	Boyd County United Way	8,500
17	Paramount Arts Center	10,000
18	Miscellaneous Items Under 5% of Account Total	123,926
19		
20	OTHER DONATIONS	
21	Company's Share of Parent Company's Donations	7,365
22		
23	TOTAL-426.1	177,001
24		
25	426.3 - PENALTIES	500
26		
27	TOTAL-426.3	500
28		
29	426.4 - EXPENDITURES FOR CERTAIN CIVIC, POLITICAL	
30	& RELATED ACTIVITIES	
31		
32	Labor	84,016
33	Transportation	2,750
34	Employee Expenses	38,854
35	Lobbying Expenses of Parent Co.	80,317
36	Employees	
	Miscellaneous Expenses	10,537
39	TOTAL-426.4	216,474

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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 accounts. 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 INCOME DEDUCTIONS	
2		
3	Write down of insider heat pumps to sales price	145,328
4	.P branding expense	143,700
5	Various Club Dues & Memberships Each	
6	Under 5% of Account Total	12,867
7	Write down of ETS furnace to est. sales price	218,000
8	Customer Financing Program	438,113
9	Miscellaneous Items under 5%	2,682
10		
[illegible]	TOTAL-426.5	960,6[illegible]
[illegible]	TOTAL 426	1,354,665
[illegible]	431 - OTHER INTEREST EXPENSE	
16		
17	Customer Deposits - 6%	206,598
18	Short Term Notes - Various	429,823
19	Commercial Paper - Various	2,353,492
20	Lines of Credit Fees	65,449
21	Other Investment Expense - Miscellaneous	1,662
22	Other Interest Expense - Emmission Allowance	
23	Carrying Charge	3,456
24		
25	TOTAL 431	3,060,480
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[illegible]		

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REGULATORY COMMISSION EXPENSES

't iculars (details) of regulatory commission ex- ing the current year (or incurred in previous ing amortized) relating to formal cases before a ody, 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.

Description name of regulatory commission or body ket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of year (e)
·sment 95-96		$136,617	$136,617	
sment 96-97		24,834	24,834	
	--	19,800	19,800	
		49,185	49,185	
		28,123	28,123	
ous		38,008	38,008	
	0	$296,567	$296,567	0

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REGULATORY COMMISSION EXPENSES (Continued)

. Show in column (k) any expenses incurred in prior years ich are being amortized. List in column (a) the period of rtization.

4. List in column (f), (g), and (h) expenses incurred durir year which were charged currently to income, plant, or othei accounts.

5. Minor items (less than $25,000) may be grouped.

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EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3, End of Year (l)	Line No.
Electric	928	$136,617					1
							2
Electric	928	24,834					3
							4
Electric	928	19,800					5
							6
Electric	928	49,185					7
							8
Electric	928	28,123					9
							10
Electric	928	38,008					11
							12
							13
							14
							15
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							41
							42
							43
							44
							45
[redacted]		$296,567	0	[redacted]	0	0	46

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (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

Classification (a)	Description (b)
ELECTRIC UTILIITY RESEARCH, DEVELOPMENT & DEMONSTRATION PERFORMED INTERNALLY	
A(1)B GENERATION: FOSSIL-FUEL STEAM	3 ITEM(S) UNDER $5,000
A(1)D GENERATION: NUCLEAR	ADVANCED PRESSURIZED WATER REACTOR DESIGN
A(2) SYSTEM PLANNING, ENGINEERING,& OPERATION:	2 ITEM(S) UNDER $5,000
A(3)A TRANSMISSION: OVERHEAD	4 ITEM(S) UNDER $5,000
A(3)B TRANSMISSION: UNDERGROUND	1 ITEM(S) UNDER $5,000
A(4) DISTRIBUTION:	4 ITEM(S) UNDER $5,000
A(5) ENVIRONMENT: (OTHER THAN EQUIPMENT)	5 ITEM(S) UNDER $5,000
A(6) OTHER:	IMPLEMENTATION OF FAULT ANALYSIS IN LIGHTING LOCATION SYSTEM (FALLS)
	PROTOTYPE OF NATIONAL ASSOCIATION OF HOME BUILDERS SMART HOUSE FIELD TEST
	6 ITEM(S) UNDER $5,000
A(7) TOTAL COST INCURRD INTERNALLY	
ELECTRIC UTILITY RESEARCH, DEVELOPMENT, & DEMONSTRATION PERFORMED EXTERNALLY	
B(1) RESEARCH SUPPORT TO THE ERC OR THE EPRI:	1 ITEM(S) UNDER $5,000
B(2) RESEARCH SUPPORT TO THE EDISON ELECTRIC INSTITUTE	1 ITEM(S) UNDER $5,000
B(5) TOTAL COST INCURRED EXTERNALLY	
GRAND TOTAL	

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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 accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
1,954		506	1,954		4
					5
8,546		930	8,546		6
					7
878		930/566	878		8
1,055		566/588	1,055		10
					11
601		588	601		12
					13
1,304		588/566	1,304		14
					15
5,627		506/930	5,627		16
					17
98,329		566	98,329		18
					19
6,596		588	6,596		20
					21
2,486		930/588	2,486		22
					23
127,376			127,376		24
					25
					26
					27
					28
					29
	2,465	506	2,465		
					31
	2,070	566	2,070		32
					33
					34
			4,535		35
					36
127,376	4,535		131,911		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	$4,714,057		
4	Transmission	566,815		
5	Distribution	2,992,455		
6	Customer Accounts	2,940,211		
7	Customer Service and Informational	1,376,033		
8	Sales	96,618		
9	Administrative and General	2,866,304		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	$15,552,493		
11	Maintenance			
12	Production	3,039,766		
13	Transmission	530,372		
14	Distribution	3,064,212		
15	Administrative and General	506,219		
16	TOTAL Maint. (Total of lines 12 thru 15)	$7,140,569		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	$7,753,823		
[illegible]	Transmission (Enter Total of lines 4 and 13)	$1,097,187		
[illegible]	Distribution (Enter Total of lines 5 and 14)	$6,056,667		
[illegible]	Customer Accounts (Transcribe from line 6)	2,940,211		
[illegible]	Customer Service and Informational(Transcribe from line 7)	1,376,033		
[illegible]	Sales (Transcribe from line 8)	96,618		
24	Administrative and General (Enter Total of lines 9 and 15)	$3,372,523		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	$22,693,062	$3,669,838	$26,362,900
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)	0		
39	Maintenance			
40	Production--Manufactured Gas			
41	Production--Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
[illegible]	Distribution			
[illegible]	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	0		

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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)
	Gas			
48	Total Operation and Maintenance			
49	Production--Manufactured Gas (Enter Total of lines 28 and 40)	0		
50	Production--Natural Gas (Including Expl. and Dev.) (Total of lines 29 and 41)	0		
51	Other Gas Supply (Enter Total of lines 30 and 42)	0		
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	0		
53	Transmission (Lines 32 and 44)	0		
54	Distribution (Lines 33 and 45)	0		
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
5	Sales (Line 36)			
5	Administrative and General (Lines 37 and 46)	0		
5	TOTAL Operation and Maint. (Total of lines 49 thru 58)	0		0
6C	Other Utility Departments			
61	Operation and Maintenance			0
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	$22,693,062	$3,669,838	$26,362,900
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	7,165,040	1,174,480	8,339,520
66	Gas Plant			
67	Other			
68	TOTAL Construction (Total of lines 65 thru 67)	$7,165,040	$1,174,480	$8,339,520
	Plant Removal (By Utility Departments)			
	Electric Plant	670,542	144,199	814,
	Gas Plant			
72	Other			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	$670,542	$144,199	$814,741
74	Other Accounts (Specify):			
75	Fuel Stock Expenses-Undistributed	918,298	(918,298)	0
76	Stores Expense-Undistributed-T&D Expense	747,035	(709,683)	37,352
77	Stores Expense-Undistributed-Power Plant	440,663	(440,663)	0
78	Transportation Expenses-Maintenance	414,053	(380,013)	34,040
79	Transportation Expenses-Accidents	950	(872)	78
80	Transportation Expenses-O&M-General & OH	176,007	(161,537)	14,470
81	Building Service-Clearing	2,013	(1,679)	334
82	MDD-Other Work In Progress	1,023,936	(1,023,936)	0
83	MDD-Unclassified Payroll	4,830	0	4,830
84	Expenditures to CNIC, Political & R/A	78,792	0	78,792
85	Unclassified NPOT/NVAC	(116,468)	0	(116,468)
86	Non-Productive Payroll	1,427,498	(1,351,836)	75,662
87				
88				
89				
90				
91				
92				
93				
	TOTAL Other Accounts	$5,117,607	($4,988,517)	$129,
96	TOTAL SALARIES AND WAGES	$35,646,251	0	$35,646,251

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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)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,427,353
3	Steam	6,030,392	23	Requirements Sales for Resale (See instruction 4, page 311.)	82,480
4	Nuclear		24	Non-Requirements Sales For Resale (See Instruction 4, page 311.)	3,597,821
5	Hydro--Conventional		25	Energy Furnished Without Charge	
6	Hydro--Pumped Storage		26	Energy Used by the Company (Electric Department Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	449,841
8	(Less) Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Thru 27) (MUST EQUAL LINE 20)	10,557,495
9	Net Generation (Enter Total of lines 3 thru 8)	6,030,392			
10	Purchases	4,527,103			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	1,097,702			
17	Delivered	1,097,702			
18	Net Transmission for Other (Line 16 minus Line 17)	0			
19	Transmission By Other Losses				
20	TOTAL (Enter Total of Lines 9, 10, 14, 18 and 19)	10,557,495			

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-Requirements Sales For Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
29	January	1,018,920	325,130	1,246	19	* 1900
30	February	995,802	361,464	1,418	5	0800
31	March	987,776	360,775	1,221	8	2000
32	April	917,846	393,443	1,030	2	0800
33	May	934,151	417,056	1,042	20	1700
34	June	959,629	432,323	1,062	17	1500
35	July	918,564	373,913	1,041	17	1500
36	August	905,911	336,408	1,087	7	1700
37	September	636,839	142,117	960	9	1600
38	October	666,481	144,449	885	21	0900
39	November	760,465	147,987	1,116	15	0900
40	December	855,111	217,944	1,262	21	0900
41	TOTAL	10,557,495	3,653,009			

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< Page 401 Line 29 Column f >

The internal AEP System Peaks for 1996 by month were:

LINE NO.	MONTH	(D) MEGAWATTS	(E) DAY OF MONTH	(F) HOUR
29	JAN	17,833	11	0900
30	FEB	19,557	05	0800
31	MAR	17,721	08	1100
32	APR	15,309	10	0800
33	MAY	17,409	20	1500
34	JUN	17,679	17	1400
35	JUL	18,072	17	1600
36	AUG	18,864	07	1600
37	SEP	16,935	05	1600
38	OCT	14,208	11	0800
39	NOV	17,077	15	0800
40	DEC	18,263	20	0900

Page 401 Footnote.1

Name of Respondent Kentucky Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

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 on 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 of the gas and the quantity of fuel burned converted to Mcf.
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.

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Line No.	Item (a)	Plant Name: BIG SANDY (b)		Plant Name: (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	STEAM		
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	CONVENTIONAL		
3	Year Originally Constructed	1963		
4	Year Last Unit was Installed	1969		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	1,096.80		
6	Net Peak Demand on Plant -- MW (60 minutes)	1,095		
7	Plant Hours Connected to Load	8,670		
8	Net Continuous Plant Capability (Megawatts)			
9	When Not Limited by Condenser Water	1,060		
10	When Limited by Condenser Water	0		
11	Average Number of Employees	176		
12	Net Generation,Exclusive of Plant Use --KWh	6,030,392,000		
13	Cost of Plant: Land and Land Rights	1,076,545		
14	Structures and Improvements	26,993,235		
15	Equipment Costs	215,149,912		
16	Total Cost	$243,219,692		
	Cost per KW of Installed Capacity (line 5)	221.7539		
	Production Expenses: Oper. Supv. & Engr.	2,572,976		
	Fuel	67,013,883		
	Coolants and Water (Nuclear Plants Only)			
21	Steam Expenses	2,745,938		
22	Steam From Other Sources			
23	Steam Transferred (Cr.)			
24	Electric Expenses	214,104		
25	Misc. Steam (or Nuclear) Power Expenses	2,055,334		
26	Rents	9,945		
27	Allowances	(264,640)		
28	Maintenance Supervision and Engineering	2,315,536		
29	Maintenance of Structures	1,639,879		
30	Maintenance of Boiler (Or Reactor) Plant	11,649,423		
31	Maintenance of Electric Plant	2,200,845		
32	Maintenance Misc. Steam (or Nuclear) Plant	828,591		
33	Total Production Expenses	$92,981,814		
34	Expenses per Net KWh	$0.0154		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	COAL	* OIL	
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	TONS	BARRELS	
37	Quantity (Units) of Fuel Burned	2,423,065	35,266	
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	11,906	138,729	
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$26.994	$29.371	
40	Average Cost of Fuel per Unit Burned	$27.247	$28.179	
41	Avg. Cost of Fuel Burned per Million Btu	$1.144	$4.836	
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.011		
43	Average Btu per KWh Net Generation	9,612.000		

< Page 402 Line 35 Column b >

Used for Startup, Banking of Boiler, Flame Stabilization, and Supplemental Firing.

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

TRANSMISSION LINE STATISTICS

Report information concerning transmission lines,cost of es, and expenses for year. List each transmission line ving nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5.Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	Big Sandy, KY	Amos, WV	765.00	765.00	ST	0.13		1
2	Big Sandy, KY	Sargents, OH	765.00	765.00	ALUM	24.20		1
3	Big Sandy, KY	Sargents, OH	765.00	765.00	ST	4.79		1
4	Big Sandy, KY	Broadford, VA	765.00	765.00	ALUM	12.65		1
5	Big Sandy, KY	Broadford, VA	765.00	765.00	ST	3.04		1
	Big Sandy, KY	Broadford, VA	765.00	765.00	ALUMT	58.26		1
	Hanging Rock, OH	Jefferson, IN	765.00	765.00	ST	154.74		1
	Big Sandy, KY	Tri-State, WV	345.00	345.00	ST	8.36		1
	Hazard, KY	Pineville, KY	161.00	161.00	WP	45.62		1
10	Hazard, KY	Pineville, KY	161.00	161.00	ST	0.72		
11	Big Sandy, KY	Bellefonte	138.00	138.00	ALUM	12.08		1
12	Big Sandy, KY	Bellefonte	138.00	138.00	ST	14.77		1
13	Big Sandy, KY	W Huntington, WV	138.00	138.00	ST	0.33		1
14	Bellefonte, KY	N Proctorville, OH	138.00	138.00	ST	1.10	1.10	1
15	Hazard, KY	Beaver Creek, KY	138.00	138.00	ST	6.17		1
16	Hazard, KY	Beaver Creek, KY	138.00	138.00	ST	22.35		1
17	Millbrook, OH	Siloam, KY	69.00	138.00	ST	1.58		1
18	Millbrook, OH	Siloam, KY	69.00	138.00	WP	0.09		1
19	Clinch River, VA	Beaver Creek, KY	138.00	138.00	ST	1.47		1
20	Clinch River, VA	Beaver Creek, KY	138.00	138.00	WP	16.92	16.92	1
21	Logan, WV	Sprigg, KY	138.00	138.00	ST	0.64		2
22	Beaver Creek, KY	Big Sandy, KY	138.00	138.00	ALUMT	32.43		1
23	Beaver Creek, KY	Big Sandy, KY	138.00	138.00	WP	10.05		1
24	Beaver Creek, KY	Big Sandy, KY	138.00	138.00	WP	16.41	0.33	1
25	Tri State, WV	Bellefonte, KY	138.00	138.00	ST	0.71	14.41	1
26	Tri State, WV	Bellefonte, KY	138.00	138.00	WP	0.38		1
27	Chadwick	KY Electric Steel	138.00	138.00	WP	7.90		1
28	Chadwick	Coalton	138.00	138.00	WP	0.98		1
29	Milbrook Park, Oh	Fullerton	138.00	138.00	WP	5.08	1.58	1
30	Beaver Creek	Spicewood	138.00	138.00	WP	26.40		1
31	Dewey	Massey	69.00	138.00	ST	3.09		1
	Besley Layne	Allen	46.00	138.00	WP	6.35		1
	Hatfield	Sprigg	138.00	138.00	WP	5.88		1
34	Hatfield	Inez	138.00	138.00	WP	14.67		1
35	Inez	Lovely	138.00	138.00	WP	6.86		1
					TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

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

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

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
954 MCMA	$258	$10,045	$10,303					1
954 MCMA	554,508	5,276,357	5,830,865					2
								3
954 MCMA	$2,665,075	$14,691,137	$17,356,212					4
								5
.5 VAR	$16,997,648	$102,812,450	$119,810,098					
MCMA	$144,744	$1,019,199	$1,163,943					-
500 MCMCU	$197,622	$1,729,879	$1,927,501					9
								10
556.5 VAR	$492,653	$1,220,850	$1,713,503					11
								12
1033.5 VAR	$8,672	$63,923	$72,595					13
397.5 MA	$4,478	$168,524	$173,002					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	$429,302	$445,412					25
								26
795 MCMA	$6,858	$223,134	$229,992					27
795 MCMA	$337,532	$422,416	$759,948					28
556.5 MCM	$374,717		$374,717					29
795 MCMA	$555,042	$408,336	$963,378					30
336.4 MCMA	$238,736	$223,476	$462,212					31
	$141,505	$1,132,585	$1,274,090					
1053 MCM		$1,415,459	$1,415,459					
35 VAR	$455,148	$3,873,584	$4,328,732					34
5 VAR	$2,783	$251,650	$254,433					35
								36

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TRANSMISSION LINE STATISTICS

Report information concerning transmission lines, cost of ...s, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Inez	Martiki	138.00	138.00	WP	0.33		1
2	Dorton	Fleming	138.00	138.00	WP	7.64		1
3	Beaver Creek	Sprigg #1	138.00	138.00	WP	32.60		1
4	Massey	Lovely	69.00	138.00	WP	4.34		1
5	Lovely	McClure	69.00	138.00	WP	6.96		1
	Engle Tap		69.00	138.00	WP	4.60		
	Big Sandy	South Neal	138.00	138.00	WP	0.01		1
	Beaver Creek	Sprigg #3	138.00	138.00				
	Bellefonte	AK Steel Oxygen Plant	138.00	138.00	ST	0.22		2
10								
11								
12								
13	69KV Lines and Below		69.00	69.00		589.56	5.93	
14								
15								
16	765KV Expenses							
17								
18	345KV Expenses							
19								
20	161KV Expenses							
21								
22	138KV Expenses							
23								
24								
25								
26								
27								
28								
29								
30								
31								
					TOTAL	1,173.46	40.27	43

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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) 12/31/96	Year of Report Dec. 31, 1996

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 succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

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

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

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
10335 VAR		$59,181	$59,181					1
MCMA	217,206	1,174,346	1,391,552					2
MCMA	$118,238	$1,192,604	$1,310,842					3
MCMA	$40,398	$292,027	$332,425					4
795 MCMA	$121,009	$451,593	$572,602					5
5 VAR	$120,301	$1,185,444	$1,305,745					
10335 VAR		$97,436	$97,436					
	$51,485		$51,485					
ACSR		$225,664	$225,664					9
								10
								11
								12
	$2,152,413	$25,644,027	$27,796,440	$91,942	$431,331	$1,729	$525,002	13
								14
								15
				$40,206	$188,618		$228,824	16
							0	17
				$1,304	$6,116		$7,420	18
							0	19
				$7,227	$33,903		$41,130	20
								21
				$42,323	$198,553		$240,876	22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								34
								35
	$26,688,496	$170,460,610	$197,149,106	$183,002	$858,521	$1,729	$1,043,252	36

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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) 12/31/96	Year of Report Dec. 31, 1996

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 underground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the estimated final completion

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Bellefonte	AK Steel Oxygen Plant	0.22	ST	20.00	2	2
	TOTAL		0.22		20.00	2	2

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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) 12/31/96	Year of Report Dec. 31, 1996

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)	LINE COST				Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Device (n)	Total (o)	
'5	ACSR		138	0	$112,832	$112,832	$225,664	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								1-
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
				0	$112,832	$112,832	$225,664	4-

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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) 12/31/96	Dec. 31, 1996

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	7.20	
2			69.00	34.00	
3					
4	Collier - Tillie	D-U	69.00	34.00	
5					
6	Dewey - Odds	T-U	138.00	69.00	12.00
7			138.00	34.00	
8					
9	Dorton - Dorton	T-U	138.00	46.00	
10					
11	Draftin - Marrowbone	D-U	46.00	12.00	
12					
13	Elkhorn City - Elkhorn City	T-U	69.00	12.00	
14			69.00	46.00	
15					
	Elwood - Virgie	T-U	46.00	34.00	
	Engle - Engle	D-U	69.00	34.50	
20	Falcon - Salyersville	T-U	69.00	46.00	
21			69.00	12.00	
22					
23	Feds Creek - Nigh	D-U	69.00	12.00	
24					
25	Fleming - Fleming	T-U	138.00	69.00	46.00
26			69.00	12.00	
27					
28	Fords Branch - Shelbiana	D-U	46.00	34.00	12.00
29					
30	Forty-Seventh St.- Ashland	D-U	69.00	12.00	
31					
32	Garrett - Garrett	D-U	46.00	34.00	
33			34.00	12.00	
34					
35	Grayson - Grayson	D-U	69.00	12.00	
36					
37	Haddix - Haddix	D-U	69.00	34.00	
38					
39	Hatfield - So. Williamson	T-U	138.00	69.00	46.00
40					

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SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
4.00	1					1
20.00	1					2
						3
25.00	1		Stat Cap	1	10	4
						5
90.00	1		Stat Cap	1	27	6
25.00	1					7
						8
45.00	1					9
						10
11.00	1					11
						12
11.00	1		Stat Cap	1	14	13
20.00	1					14
						15
25.00	1		Stat Cap	1	11	16
						17
20.00	1					18
						19
20.00	1					20
20.00	1					21
						22
20.00	1					23
						24
130.00	1		Stat Cap	1	14	25
20.00	1					26
						27
30.00	1					28
						29
20.00	1					30
						31
20.00	1					32
5.00	1					33
						34
20.00	1					35
						36
25.00	1					37
						38
130.00	1					39
						40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hazard - Lothair	T-U	138.00	69.00	12.00
2			138.00	69.00	12.00
3			161.00	138.00	34.00
4			138.00	34.00	
5			34.00	12.00	
6					
7	Ashland - Ashland	D-U	69.00	12.00	
8					
9	Baker - Louisa	T-U	765.00	345.00	34.00
10					
11	Barrenshe - Freeburn	D-U	69.00	12.00	
12					
13	Beaver Creek - Clear Cr. Jct.	T-U	138.00	69.00	46.00
14			138.00	46.00	12.00
15			69.00	12.00	
	Beckham - Hindman	D-U	138.00	34.00	
	Beefhide - Jenkins	D-U	138.00	34.50	
20					
21	Belfry - Toler	D-U	46.00	12.00	
22					
23	Belhaven - Flatwoods	D-U	138.00	12.00	
24					
25	Bellefonte - Bellefonte	T-U	138.00	34.00	
26			138.00	69.00	34.00
27			138.00	69.00	34.00
28			138.00	12.00	
29					
30	Betsy Layne - Betsy Layne	T-U	46.00	12.00	
31			138.00	69.00	46.00
32			138.00	34.00	
33					
34	Big Sandy - Louisa	T-A	138.00	4.00	
35			22.00	138.00	
36			26.00	345.00	
37			138.00	34.00	
38			138.00	34.00	12.00
39					
40	Bonnyman - Bonnyman	T-U	69.00	34.00	

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SUBSTATIONS (Continued)

Show in columns (i),(j),and (k) special equipment such rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50.00	1		Stat Cap	2	46	1
130.00	1					2
135.00	3	1				3
30.00	1					4
6.00	1					5
						6
22.00	1		Stat Cap	1	16	7
						8
1,500.00	3	1	Reactor	3	300	9
						10
25.00	1					11
						12
50.00	1		Stat Cap	8	317	13
38.00	3	1	Reactor	6	126	14
7.00	1					15
						16
25.00	1					17
						18
20.00	1					19
						20
11.00	1					21
						22
20.00	1					23
						24
45.00	1					25
196.00	1					26
100.00	1					27
20.00	1		Stat Cap	1	14	28
						29
5.00	1		Stat Cap	1	10	30
50.00	1					31
25.00	1					32
						33
38.00	2					34
300.00	2					35
950.00	1					36
20.00	1					37
8.00	1					38
						39
25.00	1					40

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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) 12/31/96	Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Busseyville - Busseyville	DU	138.00	34.00	
2					
3	Cannonsburg - Ashland	D-U	69.00	34.00	
4					
5	Cedar Creek - Pikeville	T-U	138.00	69.00	46.00
6					
7	Chadwick - Chadwicks Creek	T-U	138.00	69.00	12.00
8					
9	Coalton - Coalton	D-U	69.00	12.00	
10					
11	Henry Clay - Hellier	D-U	46.00	34.00	
12					
13	Highland - Highland	D-U	69.00	12.00	
14					
15	Hitchins - Hitchins	D-U	69.00	12.00	
16					
17	Howard Collins - Ashland	D-U	69.00	12.00	
18					
19	Inez - Inez	D-U	138.00	69.00	12.00
20					
21	Jackson - Jackson	T-U	69.00	12.00	
22					
23	Johns Creek - Kimper	T-U	138.00	69.00	34.00
24					
25	Kenwood - Paintsville	D-U	46.00	12.00	
26					
27	Keyser - Keyser	D-U	69.00	12.00	
28					
29	Leslie - Wooten	T-U	161.00	69.00	12.00
30			69.00	34.00	12.00
31					
32	Louisa - Louisa	D-U	34.00	12.00	
33					
34	Lovely - Lovely	T-A	138.00	34.50	
35					
36	Pikeville - Pikeville	D-U	69.00	12.00	
37					
38	Princess - Cannonsburg	D-U	69.00	34.00	
39					
40	Russell - Russell	D-U	69.00	12.00	

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Name of Respondent	This Report Is:	Date of Report	Year of Report
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SUBSTATIONS (Continued)

Show in co[illegible]umns (i),(j),and (k) special equipment such [illegible]otary converters, rectifiers, condensers, etc. and aux-[illegible]ry 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.

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25.00	1					1
						2
25.00	1					3
						4
90.00	1					5
						6
200.00	1					7
						8
25.00	1		Stat Cap	1	14	9
						10
30.00	1					11
						12
11.00	1					13
						14
10.00	2					15
						1[illegible]
28.00	2					[illegible]
						18
56.00	1		Stat Cap	1	10	19
						20
13.00	2		Stat Cap	1	5	21
						22
90.00	1		Stat Cap	1	10	23
						24
20.00	1					25
						26
20.00	1					27
						28
90.00	1					29
20.00	1					30
						31
10.00	2					32
						33
30.00	1					34
						35
25.00	1					36
						37
20.00	1					38
						39
22.00	1					40

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	12/31/96	Dec. 31, 1996

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	Sidney - Sidney	D-U	69.00	12.00	
2					
3	Slemp - Slemp	D-U	69.00	34.00	
4					
5	South Pikeville - Pikeville	D-U	69.00	12.00	
6					
7	Stinnett - Hoskingston	D-U	161.00	34.00	12.00
8					
9	Stone - Belfry	T-U	138.00	69.00	46.00
10					
11	Tenth Street - Ashland	D-U	69.00	12.00	
12					
13	Thelma - Paintsville	T-U	138.00	69.00	46.00
14					
15	Vicco - Vicco	D-U	138.00	34.00	
	West Paintsville - Paintsville	D-U	69.00	12.00	
	Whitesburg - Whitesburg	D-U	69.00	12.00	
21	Williamson - S. Williamson	D-U	46.00	4.00	
22					
23	Wurtland - Wurtland	D-U	69.00	12.00	
24					
25	Stations Under 10,000 KVA	T/D			
26					
27	NOTE 4 - SUMMARY CAPACITY (MVA)				
28					
29	23 Transmission Stations 4,941				
30	39 Distribution Stations 861				
31	34 Under 10MVA Stations 186				
32					
33	___ Sale for Resale Stations ___				
34	96 5,988				
35					
36					
37					
38					
39					
40					

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SUBSTATIONS (Continued)

. Show in columns (i),(j),and (k) special equipment such tary converters, rectifiers, condensers, etc. and aux- ary 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.
20.00	1					1
						2
31.00	2					3
						4
25.00	1					5
						6
20.00	2					7
						8
50.00	1					9
						10
20.00	1					11
						12
70.00	1		Stat Cap	2	40	13
						14
30.00	1					15
						16
20.00	1					17
						18
15.00	2		Stat Cap	1	13	19
						20
14.00	2					21
						22
20.00	1					23
						24
180.00	34					25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

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 parties, 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.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS Number (c)	LINE TRANSFORMERS Total Capacity (In MVa) (d)
1	Number at Beginning of Year	173,248	85,386	2,652
2	Additions During Year			
3	Purchases	9,411	3,143	435
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	9,411	3,143	435
6	Reductions During Year			
7	Retirements	5,857	2,017	402
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	5,857	2,017	402
10	Number at End of Year (Lines 1+5-9)	176,802	86,512	2,685
11	In Stock	5,880	1,366	95
12	Locked Meters on Customers' Premises	4,803		
13	Inactive Transformers on System			
	In Customers' Use	166,015	84,984	2,586
	In Company's Use	104	162	4
	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	176,802	86,512	2,685

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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) 12/31/96	Dec. 31, 1996

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 judgement 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.

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.

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Line No.	Classification of Cost (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	$123,411	$32,267	$411,346	$23,110,486	$23,110,486
2	Water Pollution Control Facilities	3,825			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	43,605			2,123,564	
7	Miscellaneous (Identify significant)					
8	TOTAL (Total of lines 1 thru 7)	$170,841	$32,267	$411,346	$34,600,597	$32,477,033
9	Construction Work in Progress				0	0

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

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	$1,205,073	$1,205,073
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	690,718	690,718
3	Fuel Related Costs		
4	Operation of Facilities	1,201,808	1,201,808
5	Fly Ash and Sulfur Sludge Removal		
6	Difference in Cost of Environmentally Clean Fuels		
	Replacement Power Costs	207,146	
	Taxes and Fees	53,138	53,138
	Administrative and General		
	Other (Identify significant)		
11	TOTAL	$3,357,883	$3,150,737

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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 [X] Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 7/31/98)

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 CFR141.1. 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, 19 97

RESPONDENT'S STATEMENT

The undersigned has examined the reports and that to the best of his knowledge and behalf all information contained in the paper copy of this report is the same information contained in the electronic media filing report.

Dated: 4/22/98

Name: G. R. KNORR
Title: Assistant Controller

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 stating 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 certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 41.10-41.12 for specific qualifications.)

III. What and Where to Submit (Continued)

(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 NE., Washington, DC 20426 (Attention: Mr. Michael Miller, 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.

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 shall not include `municipalities' as hereinafter defined;

(4) `person' means an individual or a corporation;

(5) `licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) `municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, 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 may prescribe the manner and form in which such reports shall be made, amd 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, amend, 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, 1997
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) 1701 CENTRAL AVENUE, ASHLAND, KENTUCKY 41105		
05 Name of Contact Person G. C. DEAN		06 Title of Contact Person DIR. - FINANCIAL REPORTING
07 Address of Contact Person (Street, City, State, Zip Code) AEPSC, 1 RIVERSIDE PLAZA, COLUMBUS, OHIO 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) 12/31/97

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 G. R. KNORR	03 Signature G. R. Knorr	04 Date Signed (Mo, Da, Yr) 04/21/98
02 Title ASSISTANT CONTROLLER		
Title 18, U.S.C. 1001, makes it a crime for any person 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.		

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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) 12/31/97	Year of Report Dec. 31, 1997

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) 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".

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101	Ed. 12-87	
Control Over Respondent	102	Ed. 12-96	
Corporations Controlled by Respondent	103	Ed. 12-96	NA
Officers	104	Ed. 12-96	
Directors	105	Ed. 12-95	
Security Holders and Voting Powers	106 - 107	Ed. 12-96	
Important Changes During the Year	108 - 109	Ed. 12-96	
Comparative Balance Sheet	110 - 113	Ed. 12-94	
Statement of Income for the Year	114 - 117	Ed. 12-96	
Statement of Retained Earnings for the Year	118 - 119	Ed. 12-96	
Statement of Cash Flows	120 - 121	Ed. 12-96	
Notes to Financial Statements	122 - 123	Ed. 12-96	
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200 - 201	Ed. 12-89	
Nuclear Fuel Materials	202 - 203	Ed. 12-89	NA
Electric Plant in Service	204 - 207	Rev. 12-95	
Electric Plant Leased to Others	213	Rev. 12-95	NA
Electric Plant Held for Future Use	214	Ed. 12-89	
Construction Work in Progress -- Electric	216	Ed. 12-87	
Construction Overheads -- Electric	217	Ed. 12-89	
General Description of Construction Overhead Procedure	218	Ed. 12-88	
Accumulated Provision for Depreciation of Electric Utility Plant.	219	Ed. 12-88	
Nonutility Property	221	Rev. 12-95	
Investment in Subsidiary Companies	224 - 225	Ed. 12-89	NA
Materials and Supplies	227	Ed. 12-96	
Allowances	228 - 229	Ed. 12-95	
Extraordinary Property Losses	230	Ed. 12-93	NA
Unrecovered Plant and Regulatory Study Costs	230	Ed. 12-93	NA
Other Regulatory Assets	232	Ed. 12-95	
Miscellaneous Deferred Debits	233	Ed. 12-94	
Accumulated Deferred Income Taxes (Account 190)	234	Ed. 12-88	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Capital Stock	250 - 251	Ed. 12-91	
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252	Rev. 12-95	NA
Other Paid-in Capital	253	Ed. 12-87	
Discount on Capital Stock	254	Ed. 12-87	NA
Capital Stock Expense	254	Ed. 12-86	NA
Long-Term Debt	256 - 257	Ed. 12-96	

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	Ed. 12-96	
Taxes Accrued, Prepaid and Charged During Year	262 - 263	Ed. 12-96	
Accumulated Deferred Investment Tax Credits	266 - 267	Ed. 12-89	
Other Deferred Credits	269	Ed. 12-88	
Accumulated Deferred Income Taxes -- Accelerated Amortization Property	272 - 273	Ed. 12-96	NA
Accumulated Deferred Income Taxes -- Other Property	274 - 275	Ed. 12-96	
Accumulated Deferred Income Taxes -- Other	276 - 277	Ed. 12-96	
Other Regulatory Liabilities	278	Ed. 12-94	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	300 - 301	Ed. 12-96	
Sales of Electricity by Rate Schedules	304	Ed. 12-95	
Sales of Resale	310 - 311	Ed. 12-88	
Electric Operation and Maintenance Expenses	320 - 323	Ed. 12-95	
Number of Electric Department Employees	323	Ed. 12-93	
Purchased Power	326 - 327	Ed. 12-95	
Transmission of Electricity for Others	328 - 330	Ed. 12-90	
Transmission of Electricity by Others	332	Ed. 12-90	
Miscellaneous General Expenses -- Electric	335	Ed. 12-94	
Depreciation and Amortization of Electric Plant	336 - 337	Ed. 12-95	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	Ed. 12-87	
COMMON SECTION			
Regulatory Commission Expenses	350 - 351	Ed. 12-96	
Research, Development and Demonstration Activities	352 - 353	Ed. 12-87	
Distribution of Salaries and Wages	354 - 355	Ed. 12-88	
Common Utility Plant and Expenses	356	Ed. 12-87	NA
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401	Rev. 12-90	
Monthly Peaks and Output	401	Rev. 12-90	
Steam-Electric Generating Plant Statistics (Large Plants)	402 - 403	Rev. 12-95	
Hydroelectric Generating Plant Statistics (large Plants)	406 - 407	Ed. 12-89	NA
Pumped Storage Generating Plant Statistics (Large Plants)	408 - 409	Ed. 12-88	NA
Generating Plant Statistics (Small Plants)	410 - 411	Ed. 12-87	NA

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Line Statistics	422 - 423	Ed. 12-87	
Transmission Lines Added During Year	424 - 425	Ed. 12-86	NA
Substations	426 - 427	Ed. 12-96	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental Protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	NA
Stockholders' Reports Check appropriate box:			
[X] Four copies will be submitted.			
[ ] No annual report to stockholders is prepared.			

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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 the office where any other corporate books are kept, if different from that where the general corporate books are kept.

George E. Laurey, Director of Utility Ledger Accounting
AEPSC, 1 Riverside Plaza
Columbus, OH 43215

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

Kentucky
July 21, 1919

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - Kentucky

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the the principal accountant for your previous year's certified financial statements?

Yes...Enter the date when such independent accountant was initially engaged:

X No

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

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of 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 beneficiaries for whom trust was maintained, and purpose of the trust.

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

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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) 12/31/97	Year of Report Dec. 31, 1997

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 policymaking 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 copy only.		
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< Page 104 Line 1 Column A >

Executive Compensation

The following table shows for 1997 the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by regulations of the Securities and Exchange Commission) of the Company at December 31, 1997.

Summary Compensation Table

	Annual Compensation		Long-Term Compensation Payouts	
Name and Principal Position	Salary ($)	Bonus ($) (1)	LTIP Payouts ($) (1)	All Other Compensation ($) (2)
E. Linn Draper, Jr. - Chairman of the board and chief executive officer of the Company; chairman of the board, president and chief executive officer of AEP Co., Inc. and the Service Corporation; chairman of the board and chief executive officer of other AEP System companies	720,000	327,744	951,132	31,620
Peter J. DeMaria - Vice president, controller and director of the Company; controller and director of AEP Co., Inc.; vice chairman and director of the Service Corporation; vice president, controller and director of other AEP System companies	385,000	153,345	391,793	21,570
G. P. Maloney - Vice president and director of Company; vice president, secretary and director of AEP Co., Inc.; vice chairman and director of the Service Corporation; vice president and director of other AEP System companies	385,000	153,345	391,793	21,570

Page 104 Footnote.1

William J. Lhota - President, chief operating officer and director of the Company; executive vice president and director of the Service Corporation; president, chief operating officer and director of other AEP System companies	355,000	141,396	364,436	20,570
James J. Markowsky - Vice president and director of the Company; executive vice president-power generation and director of the Service Corporation; vice president and director of other AEP System companies	325,000	129,447	338,382	18,020

(1) Amounts in the "Bonus" column reflect payments under the Senior Officer Annual Incentive Compensation Plan (and predecessor Management Incentive Compensation Plan) for performance measured for the year ended December 31, 1997. Payments are made in March of the subsequent year. Amounts for 1997 are estimates but should not change significantly.

Amounts in the "Long-Term Compensation" column reflect performance share unit targets earned under the Performance Share Incentive Plan (which became effective January 1, 1994) for the three-year performance periods ending December 31, 1997.

(2) For 1997, includes (i) employer matching contributions under the AEP System Employees Savings Plan: Dr. Draper, $3,400; Mr. DeMaria, $3,306; Mr. Maloney, $4,800; Mr. Lhota, $4,800; and Dr. Markowsky, $3,250; (ii) employer matching contributions under the AEP System Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan: Dr. Draper, $18,200; Mr. DeMaria, $8,244; Mr. Maloney, $6,750; Mr. Lhota, $5,850; and Dr. Markowsky, $6,500; and (iii) subsidiary companies director fees: Dr. Draper and Messrs. DeMaria and Maloney, $10,020; Mr. Lhota, $9,920; and Dr. Markowsky, $8,270.

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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	
2	Chief Executive Officer	Columbus, OH
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
46	(A) Company does not have an Executive Committee.	

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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 and give other important particulars (details) concerning the voting rights of such security. State whether voting rights 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 for 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 rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any 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 general public where the options, warrants, or rights were issued on a prorata basis.

1. Give 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 or 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 12, 1997 Columbus, OH

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): December 31, 1997 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1,009,000	1,009,000	0	0
5	TOTAL number of security holders	1	1	0	0
6	TOTAL votes of Security holders listed below	1,009,000	1,009,000	0	0
7	American Electric Power Company, Inc.				
8	1 Riverside Plaza				
9	Columbus, OH 43215	1,009,000	1,009,000	0	0
10					
11					
12					
13					
14					
15					
16	Item 2. None				
17	Item 3. None				
18	Item 4. None				

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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 therefor 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 conditions. 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

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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
3/4/97	Whitesburg, KY	20 years	25% of street lighting payments

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:

   $48,000,000 6.91% Unsecured Medium Term Notes, Series A due 2007

   SEC File No. 70-8693 under the Public Utility Holding Company Act of 1935. Short-term borrowing authority not to exceed $150,000,000 for the period January 1, 1996 through December 31, 2000.

7. None

8. Salary and wage increases include a 3.0% general increase for physical employees. Also included is a 3.0% base merit budget increase for exempt employees; a 2.8% base merit budget increase for the nonexempt clerical employees; and a 3.0% base merit budget increase for nonexempt technical employees.

9. On April 24, 1996, the Federal Energy Regulatory Commission (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 FERC'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

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IMPORTANT CHANGES DURING THE YEAR (Continued)

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, including Kentucky Power Company (KEPCo), 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. On January 15, 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, but supports the formation of voluntary ISOs, and is currently examining its options, which include, among others, participation in the Midwest ISO.

KEPCo and Appalachian Power Company (APCo), an AEP System company, have announced an improvement plan to be implemented during a four-year period (1996-1999) to reinforce their 138,000-volt transmission system. Included in this plan is a new transmission line to link KEPCo's Big Sandy Plant to communities in eastern Kentucky. APCo's and KEPCo's estimated project costs are $5,800,000 and $81,600,000, respectively. The Kentucky Public Service Commission (Kentucky PSC) approved the project in its order dated June 11, 1996. Construction commenced in late 1996.

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 (SO_2), 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 SO_2 control under the Acid Rain Program. Phase I, effective January 1, 1995, requires SO_2 emission reductions from certain units that emitted SO_2 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 SO_2 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 SO_2 emission control requirements beginning January 1, 2000. If a unit emitted SO_2 in 1985 at a rate in excess of 1.2 pounds per million Btu heat input, the

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IMPORTANT CHANGES DURING THE YEAR (Continued)

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. On February 13, 1998, the U.S. Court of Appeals for the District of Columbia Circuit, in an appeal in which the AEP System operating companies participated, upheld the emission limitations.

The Clean Air Act (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. Title I, dealing generally with attainment of federally set National Ambient Air Quality Standards (NAAQS), establishes a tiered system for classifying degrees of nonattainment with the one-hour NAAQS for ozone. Depending upon the severity of non-attainment within a given non-attainment area, reductions in NOx emissions from fossil fuel-fired power plants may be required as part of a state's plan for achieving attainment with the one-hour ozone NAAQS. While one-hour ozone NAAQS non-attainment is largely restricted to urban areas, AEP System generating units could be determined to be affecting downwind urban ozone concentrations and may therefore, eventually be required to reduce NOx emissions pursuant to Title I.

In July 1997, Federal EPA revised the ozone and particulate matter 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). 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. The AEP System operating companies joined with other utilities to appeal the revised NAAQS by filing petitions for review in August and September 1997 in the U.S. Court of Appeals for the District of Columbia Circuit.

On July 9, 1997, Federal EPA proposed revisions to the New Source

IMPORTANT CHANGES DURING THE YEAR (Continued)

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./megawatt-hour net energy output) for coal-fired boilers as for gas-fired boilers. If finalized, the proposal would effectively require costly selective catalytic reduction or comparable technology to control NOx emissions from new or modified coal-fired boilers.

In 1995, the Environmental Council of States formed the Ozone Transport Assessment Group (OTAG) to study the role of transport of ozone and ozone precursor emissions (primarily NOx) in contributing to ozone nonattainment in the Northeast, Chicago, and Atlanta nonattainment areas. OTAG was comprised of the environmental commissioners of 37 eastern states, members of Federal EPA and representatives from environmental and industry groups. OTAG studied the ozone problem for two years, conducting extensive modeling and analysis of ozone levels and the effects of ozone transport. OTAG submitted its final recommendations to Federal EPA in July 1997.

After receipt of the OTAG recommendations, Federal EPA in October 1997 issued a notice (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 proposed NOx transport SIP call would establish state-by-state NOx emission budgets for the five-month ozone season to be met by the year 2002. The proposed NOx budgets apply to 22 eastern states and are premised mainly on the assumption of controlling power plant NOx emissions to 0.15 lb./MBtu (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 NOx reductions called for by Federal EPA are clearly targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to obtain new and modified source permits. The cost of meeting NOx emissions reduction requirements that might be imposed as a result of the NOx transport SIP call cannot be precisely predicted at this time, but could be significant.

On or about August 14, 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 power plants in midwestern states, including all the coal-fired plants of AEP's operating subsidiaries, prevent the Northeast 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.

Federal EPA on or about December 19, 1997 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.

IMPORTANT CHANGES DURING THE YEAR (Continued)

The MOA calls for a proposed rulemaking on the Section 126 petitions by September 30, 1998 and final action by April 30, 1999 (subject to certain limited exceptions). On January 9, 1998, a number of utilities, including the operating companies of the AEP System, filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the MOA. On February 25, 1998, the eight northeastern states filed an action in the U.S. District Court for the Southern District of New York seeking an order directing Federal EPA to rule on the Section 126 petitions within 60 days of receipt.

On January 30, 1998, the U.S. Court of Appeals for the District of Columbia Circuit remanded the final rule promulgated in May 1996 by Federal EPA reaffirming the existing primary NAAQS for SO2. The Court directed Federal EPA to provide additional justification for the rule but did not specify a schedule for completion.

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.

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

IMPORTANT CHANGES DURING THE YEAR (Continued)

stringency of the emission limits to which AEP System plants are subject. On March 10, 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. Oral argument in that case is scheduled to be heard on April 21, 1998.

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 (CO2), 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 Kyoto Protocol will be available for signature from March 1998 to March 1999 and requires ratification by at least 55 nations that account for at least 55% of developed countries' 1990 emissions of CO2 to enter into force. The agreement is not expected to be sent to the U.S. Senate for ratification before 1999.

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. The effects of this proposed intervention program on AEP operations cannot be predicted at this time.

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. This is accomplished using a unit of measurement known as a "deciview." The plan's goal is to reduce visibility impairment by one deciview or more over each 10-15 year period. The final time period will be set as part of the final rulemaking.

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

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IMPORTANT CHANGES DURING THE YEAR (Continued)

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. The Court recently requested that the parties submit proposed briefing schedules.

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. 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

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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	$895,990,667	$966,806,725
3	Construction Work in Progress (107)	200-201	48,400,480	32,059,799
4	TOTAL UTILITY PLANT (Enter Total of lines 2 and 3)		$944,391,147	$998,866,524
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	279,428,995	288,229,516
6	Net Utility Plant (Enter Total of line 4 Less 5)	-	$664,962,152	$710,637,008
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of lines 7 Less 8)	-	0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	$664,962,152	$710,637,008
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	-		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	973,644	973,644
15	(Less) Accum. Prov. for Depr. and Amort. (122)	-	152,508	159,168
16	Investments in Associated Companies (123)	-		
17	Investment in Subsidiary Companies (123.1)	224-225		
18	(For Cost of Account 123.1, See Footnote Page 224, Line 42)	-		
19	Noncurrent Portion of Allowances	228-229		
20	Other Investments (124)		5,622,152	5,768,572
21	Special Funds (125-128)	-	8,528	8,528
22	TOTAL Other Property and Investments (Total of lines 14—17,19—21)		$6,451,816	$6,591,576
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)	-	934,931	1,217,448
25	Special Deposits (132-134)	-	109,558	109,558
26	Working Fund (135)	-	61,903	54,114
27	Temporary Cash Investments (136)	-		
28	Notes Receivable (141)			
29	Customer Accounts Receivable (142)	-	22,861,474	24,127,289
30	Other Accounts Receivable (143)	-	2,186,780	2,529,668
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	271,658	524,659
32	Notes Receivable from Associated Companies (145)	-		
33	Accounts Receivable from Assoc. Companies (146)	-	2,197,855	1,722,195
34	Fuel Stock (151)	227	8,806,227	10,379,192
35	Fuel Stock Expenses Undistributed (152)	227	437,997	306,130
36	Residuals (Elec) and Extracted Products (153)	227		
37	Plant Materials and Operating Supplies (154)	227	8,777,633	7,752,082
38	Merchandise (155)	227	0	0
39	Other Materials and Supplies (156)	227		
40	Nuclear Materials Held for Sale (157)	202-203/227		
41	Allowances (158.1 and 158.2)	228-229	4,685,726	6,152,259
42	(Less) Noncurrent Portion of Allowances	228-229		
43	Stores Expense Undistributed (163)	-	(288,049)	149,395
44	Gas Stored Underground-Current (164.1)	-		
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	-		
46	Prepayments (165)	-	1,923,224	1,447,743
47	Advances for Gas (166-167)	-		
48	Interest and Dividends Receivable (171)	-		
49	Rents Receivable (172)	-	1,342,344	746,621
50	Accrued Utility Revenues (173)	-	8,174,905	12,980,99
51	Miscellaneous Current and Accrued Assets (174)		87,448	89,0
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		$62,028,298	$69,239,053

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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)	-	$584,778	$626,127
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
57	Other Regulatory Assets (182.3)	232	105,697,228	106,892,346
58	Prelim. Survey and Investigation Charges (Electric) (183)	-	4,324,480	3,871,606
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	-		
60	Clearing Accounts (184)	-	216,722	88,010
61	Temporary Facilities (185)	-	35,419	0
62	Miscellaneous Deferred Debits (186)	233	6,199,157	5,573,320
63	Def. Losses from Disposition of Utility Plt. (187)	-		
64	Research, Devel. and Demonstration Expend. (188)	352-353		
65	Unamortized Loss on Reacquired Debt (189)	-	875,419	756,855
66	Accumulated Deferred Income Taxes (190)	234	30,918,588	34,276,230
67	Unrecovered Purchased Gas Costs (191)	-		
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		$148,851,791	$152,084,494
69	TOTAL Assets and other Debits (Enter Total of lines 10,11,12, 22,52,and 68)		$882,294,057	$938,552,131

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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) 12/31/97	Year of Report Dec. 31, 1997

COMPARATIVE BALANCE SHEET (LIABILITES 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		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252		
7	Other Paid-in Capital (208-211)	253	108,750,000	128,750,000
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	84,090,394	78,076,120
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250-251		
14	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 13)	-	$243,290,394	$257,276,120
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	220,000,000	220,000,000
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257		
19	Other Long-Term Debt (224)	256-257	75,000,000	123,000,000
20	Unamortized Premium on Long-Term Debt (225)	-	0	0
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	1,801,804	1,949,512
22	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-	$293,198,196	$341,050,488
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases-Noncurrent (227)	-	9,833,194	15,006,077
25	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-	2,790,258	3,117,80
27	Accumulated Provision for Pensions and Benefits (228.3)	-	110,882	8,569,346
28	Accumulated Miscellaneous Operating Provisions (228.4)	-	6,732,542	0
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		$19,466,876	$26,693,230
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-	51,675,000	36,500,000
33	Accounts Payable (232)	-	16,272,200	13,841,921
34	Notes Payable to Associated Companies (233)	-		
35	Account Payable to Associated Companies (234)	-	14,784,916	10,732,586
36	Customer Deposits (235)	-	3,408,527	3,660,023
37	Taxes Accrued (236)	262-263	5,064,182	6,129,640
38	Interest Accrued (237)	-	5,216,744	6,015,232
39	Dividends Declared (238)	-		
40	Matured Long-Term Debt (239)	-		
41	Matured Interests (240)	-		
42	Tax Collections Payable (241)	-	1,415,195	2,091,410
43	Miscellaneous Current and Accrued Liabilities (242)		4,766,731	9,124,580
44	Obligations Under Capital Leases-Current (243)		3,016,654	3,719,047
45	TOTAL Current and Accrued Liabilities(Enter Total of lines 32 thru 44)		$105,620,149	$91,814,439

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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)		$260,560	$222,840
48	Accumulated Deferred Investment Tax Credits (255)	266-267	17,007,124	15,614,829
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	55,777	173,691
51	Other Regulatory Liabilities (254)	278	18,938,562	17,485,182
52	Unamortized Gain on Reacquired Debt (257)	269		
53	Accumulated Deferred Income Taxes (281-283)	272-277	184,456,419	188,221,312
54	TOTAL Deferred Credits (Enter Total of Lines 47 thru 53)		$220,718,442	$221,717,854
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of Lines 14, 22, 30, 45 and 54)		$882,294,057	$938,552,131

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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 duing 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	$359,543,351	$323,320,876
3	Operating Expenses			
4	Operation Expenses (401)	320-323	242,579,173	212,733,727
5	Maintenance Expenses (402)	320-323	24,416,844	32,793,010
6	Depreciation Expense (403)	336-337	26,247,598	25,084,571
7	Amort. & Depl. of Utility Plant (404-405)	336-337	187,562	0
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616
9	Amort. of Property Losses, Unrecovered 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	7,122,376	7,080,115
14	Income Taxes - Federal (409.1)	262-263	10,425,322	5,118,4[illegible]
15	- Other (409.1)	262-263	2,274,411	709,738
16	Provision for Deferred Income Taxes (410.1)	234,272-277	15,639,772	13,395,997
17	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277	14,979,754	11,539,377
18	Investment Tax Credit Adj. - Net (411.4)	266	(1,219,380)	(1,232,340)
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)		45,281	2,204,396
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of Lines 4 thru 22)		$312,687,259	$281,978,137
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		$46,856,092	$41,342,739

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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
$359,543,351	$323,320,876					2
						3
242,579,173	212,733,727					4
24,416,844	32,793,010					5
26,247,598	25,084,571					6
187,562	0					7
38,616	38,616					8
						9
						10
						11
						12
7,122,376	7,080,115					13
10,425,322	5,118,476					14
2,274,411	709,738					15
15,639,772	13,395,997					16
14,979,754	11,539,377					17
(1,219,380)	(1,232,340)					18
						19
						20
45,281	2,204,396					21
						22
$312,687,259	$281,978,137					23
$46,856,092	$41,342,739					24

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STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)	--	$46,856,092	$41,342,739
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)			
30	(Less) Costs and Exp. of Merchandising,Job. & Contract Work (416)		24,237	0
31	Revenues From Nonutility Operations (417)			
32	(Less) Expenses of Nonutility Operations (417.1)			
33	Nonoperating Rental Income (418)		53,679	58,559
34	Equity in Earnings of Subsidiary Companies (418.1)	119		
35	Interest and Dividend Income (419)		121,665	25,177
36	Allowance for Other Funds Used During Construction (419.1)		45,067	0
37	Miscellaneous Nonoperating Income (421)		30,812	65,953
38	Gain on Disposition of Property (421.1)		2,760	493
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$229,746	$150,182
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		0	83,643
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	1,199,895	1,354,665
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$1,199,895	$1,438,308
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	30,000	41,246
47	Income Taxes - Federal (409.2)	262-263	(359,119)	(473,600)
48	Income Taxes - Other (409.2)	262-263	(84,650)	(111,634)
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	316,095	249,397
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)	234,272-277	235,260	242,34[illegible]
51	Investment Tax Credit Adj. - Net (411.5)		(172,915)	(157,45[illegible]
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		($505,849)	($694,388)
54	Net Other Income and Deductions (Enter Total of lines 39, 44, 53)		($464,300)	($593,738)
55	Interest Charges			
56	Interest on Long-Term Debt (427)		23,463,456	21,359,411
57	Amort. of Debt Disc. and Expense (428)		239,113	224,328
58	Amortization of Loss on Reacquired Debt (428.1)		118,564	120,104
59	(Less) Amort. of Premium on Debt - Credit (429)		0	1,344
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340	3,235,475	3,060,480
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,410,554	986,963
64	Net Interest Charges (Enter Total of lines 56 thru 63)		$25,646,054	$23,776,016
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$20,745,738	$16,972,985
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)		$20,745,738	$16,972,985

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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 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)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance - Beginning of Year		$84,090,394
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Acc. 439) (Total of lines 4 thru 8)		
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acc. 439) (Total of lines 10 thru 14)		
16	Balance Transferred from Income (Account 433 less Account 418.1)	117	20,745,738
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acc. 436) (Total of lines 18 thru 21)		
23	Dividends Declared - Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared - Preferred Stock (Acct. 437) (Total of lines 24 thru 28)		
30	Dividends Declared - Common Stock (Account 438)		
31	Common Stock		(26,760,012)
32			
33			
34			
35			
36	TOTAL Dividends Declared - Common Stock (Acct. 438) (Total of lines 31 thru 35)		($26,760,012)
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
38	Balance - End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36, and 37)		$78,076,120

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE,FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter total of lines 45 and 46)	
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter total of lines 38 and 47)	$78,076,120
	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	Other Changes (Explain)	
53	Balance - End of Year (Total of 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 pages 122-123. Information about noncash investing and financing activities should be provided on pages 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 pages 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 (Line 72(c) on page 117)	$20,745,738
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	26,486,312
5	Amortization of (Specify)	
6	Debt Expense Discount and Premium	239,113
7	Gain or Loss on Reacquired Debt	118,564
8	Deferred Income Taxes (Net)	740,853
9	Investment Tax Credit Adjustment (Net)	(1,392,295)
10	Net (Increase) Decrease in Receivables	(284,319)
11	Net (Increase) Decrease in Inventory	(2,319,524)
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	(6,482,609)
14	Net (Increase) Decrease in Other Regulatory Assets	(1,720,765)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(1,261,335)
16	(Less) Allowance for Other Funds Used During Construction	45,067
17	(Less) Undistributed Earnings from Subsidiary Companies	
18	Other:Net (Increase) in Accrued Utility Revenues	(4,806,094)
19	Other Operating Items (Net)	11,246,091
20		
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	$41,264,663
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (Including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(66,686,924)
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	45,067
31	Other:	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	($66,641,857)
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 (Continued)

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)	($66,641,857)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long - Term Debt (b)	47,586,934
62	Preferred Stock	
63	Common Stock	
64	Other: Capital Contributions	20,000,000
65		
66	Net Increase in Short - Term Debt (c)	(15,175,000)
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	$52,411,934
71		
72	Payments for Retirement of:	
73	Long - term Debt (b)	
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	(26,760,012)
82	Net Cash provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	$25,651,922
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57,and 83)	$274,728
87		
88	Cash and Cash Equivalents at Beginning of Year	1,106,392
89		
90	Cash and Cash Equivalents at End of Year	1,381,120

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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

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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, sale, purchase, transmission and distribution of electric power serving 168,000 retail customers in eastern Kentucky. Wholesale electric power is supplied to neighboring utility systems, power marketers and the American Electric Power (AEP) System Power Pool (Power Pool). As a member of the AEP Power Pool and a signatory company to the American Electric Power System (AEP System) Transmission Equalization Agreement, KPCo's 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 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 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) No. 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 1997 and 1996 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 as follows:

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

Expenditures to demolish and remove plant are recovered through depreciation charges included in rates.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments

NOTES TO FINANCIAL STATEMENTS (Continued)

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 adjustment mechanism. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

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

Based on directives of regulatory commissions, the Company reflected investment tax credits in rates and on its books on a deferral basis. Commensurate with rate treatment deferred investment tax credits are being amortized over the life of the related plant investment. The Company's policy with regard to investment tax credits for nonutility property is to practice the flow-through method of accounting.

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 the debt is refinanced, the 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.

NOTES TO FINANCIAL STATEMENTS (Continued)

2. RATE MATTERS

In a May 27, 1997 order the KPSC approved the Company's request to establish a monthly surcharge to recover environmental compliance costs. In approving the surcharge the KPSC denied inclusion of certain environmental compliance costs in the surcharge. The surcharge was applied to bills rendered on and after July 7, 1997. However, as part of the May 27, 1997 order the KPSC directed the Company to refund to ratepayers emission allowance sale proceeds, through a reduction of the first twelve months of environmental surcharge revenues. This matter is being appealed. The ultimate resolution of this matter will not have a significant impact on results of operation, cash flows or financial condition.

3. 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. Aggregate construction program expenditures for 1998-2000 are estimated to be $139 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 $12 million at December 31, 1997.

Revised Air Quality Standards

On July 18, 1997, the United States Environmental Protection Agency published a revised National Ambient Air Quality Standard (NAAQS) for ozone and a new NAAQS for fine particulate matter (less than 2.5 microns in size). The new ozone standard is expected to result in redesignation of a number of areas of the country that are currently in compliance with the existing standard to nonattainment status which could ultimately dictate more stringent emission restrictions for AEP System generating units. New stringent emission restrictions on AEP System generating units to achieve attainment of the fine particulate matter standard could also be imposed. The AEP System operating companies joined with other utilities to appeal the revised NAAQS and filed petitions for review in August and September 1997 in the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to estimate compliance costs without knowledge of the reductions that may be necessary to meet the new standards. If such costs are significant, they could have a material adverse effect on results of operations, cash flows and possibly financial condition unless recovered.

Litigation

KPCo is involved in a number of 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.

4. 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:

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	Year Ended December 31, 1997	1996
	(in thousands)	
d Charge	$39,993	$39,622
y Charge	28,393	27,743
Total	$68,386	$67,365

nefits and costs of the System's generating plants are shared mbers of the AEP Power Pool. The Company is a member of the Pool. Under the terms of the System Interconnection ment, capacity charges and credits are designed to allocate ost of the System's generating reserves among the Power Pool rs based on their relative peak demands and generating ves. Power Pool members are also compensated for the out-of-pocket of energy delivered to the Power Pool and charged for y received from the Power Pool.

erating revenues include $41.0 million in 1997 and $28.0 on in 1996 for energy supplied to the Power Pool.

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

	Year Ended December 31, 1997	1996
	(in thousands)	
ity Charge	$ 7,196	$ 6,425
y Charge	13,855	19,741
Total	$21,051	$26,166

wer Pool members share in wholesale sales to unaffiliated ies made by the Power Pool. The Company's share of these sale power pool sales was included in operating revenues in mount of $45.9 million in 1997 and $26.7 million in 1996.

addition, the Power Pool purchases power from unaffiliated nies for resale to other unaffiliated entities. The Company's of these purchases was included in purchased power expense otaled $24.5 million (including new power marketing actions) in 1997 and $3.0 million in 1996. Revenues from transactions, including a transmission fee for power that s through the AEP System transmission network, are included in bove Power Pool wholesale operating revenues.

NOTES TO FINANCIAL STATEMENTS (Continued)

AEP System companies participate in a 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 $2.7 million and $3.3 million in 1997 and 1996, respectively.

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed by AEPSC on a direct-charge basis to the extent practicable, and on reasonable bases of proration for indirect costs. The charges 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.

5. BENEFIT PLANS:

KPCo participates in the AEP System pension plan, a trusteed, noncontributory defined benefit plan covering all employees meeting eligibility requirements. Benefits are based on service years and compensation levels. Pension costs are allocated by first charging each System company with its service cost and then allocating the remaining pension cost in proportion to its share of the projected benefit obligation. The funding policy is to make annual trust fund contributions equal to the net periodic pension cost up to the maximum amount deductible for federal income taxes, but not less than the minimum required contribution in accordance with the Employee Retirement Income Security Act of 1974. Net pension plan costs for the years ended December 31, 1997 and 1996 were $424,000 and $812,000, respectively.

Postretirement benefits other than pensions (OPEB) are provided for retired employees under an AEP System plan. Substantially all employees are eligible for postretirement health care and life insurance if they retire from active service after reaching age 55 and have at least 10 service years. OPEB costs are determined by the application of AEP System actuarial assumptions to each operating company's employee complement. The annual accrued costs, which includes the recognition of one-twentieth of the prior service transition obligation, were $2.1 million in 1997 and $2.8

million in 1996. The funding policy for AEP's OPEB plan is to make contributions to an external Voluntary Employees Beneficiary Association trust fund equal to the incremental OPEB costs (i.e., the amount that the total postretirement benefits cost under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," exceeds the pay-as-you-go amount). Contributions were $1.1 million in 1997 and $1.3 million in 1996.

An employee savings plan is offered which allows participants to contribute up to 17% of their salaries into various investment alternatives, including AEP Co., Inc. common stock. An employer matching contribution, equaling one-half of the employees' contribution to the plan up to a maximum of 3% of the employees' base salary, is invested in AEP Co., Inc. common stock. The Company's annual contributions totaled $714,000 in 1997 and $687,000 in 1996.

6. COMMON SHAREHOLDER'S EQUITY:

The Company received from AEP Co., Inc. cash capital contributions of $20 million in 1997 and $30 million in 1996 which were credited to paid-in capital. There were no other transactions affecting common stock and paid-in capital accounts in 1997 and 1996.

7. FEDERAL INCOME TAXES:

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

	Year Ended December 31, 1997	1996
	(in thousands)	
Charged (Credited) to Operating Expenses (net):		
Current	$10,425	$ 5,118
Deferred	660	1,857
Deferred Investment Tax Credits	(1,219)	(1,232)
Total	9,866	5,743
Charged (Credited) to Nonoperating Income (net):		
Current	(359)	(473)
Deferred	81	7
Deferred Investment Tax Credits	(173)	(158)
Total	(451)	(624)
Total Federal Income Taxes as Reported	$ 9,415	$ 5,119

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, 1997	Year Ended December 31, 1996
	(in thousands)	
Net Income	$20,746	$16,973
Federal Income Taxes	9,415	5,119
Pre-tax Book Income	$30,161	$22,092
Federal Income Taxes on Pre-tax Book Income at Statutory Rate (35%)	$10,556	$ 7,732
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:		
Depreciation	1,850	1,694
Removal Costs	(840)	(979)
Amortization of Deferred Federal Income Tax in Excess of the Statutory Tax Rate	-	(339)
Allowance For Funds Used During Construction	(364)	(389)
Percentage Repair Allowance	(456)	(445)
Corporate Owned Life Insurance	(328)	(479)
Investment Tax Credits (net)	(1,392)	(1,390)
Other	389	(286)
Total Federal Income Taxes as Reported	$ 9,415	$ 5,119
Effective Federal Income Tax Rate	31.2%	23.2%

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

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NOTES TO FINANCIAL STATEMENTS (Continued)

	December 31, 1997	1996
	(in thousands)	
Deferred Tax Assets	$ 34,276	$ 30,919
Deferred Tax Liabilities	(188,221)	(184,457)
Net Deferred Tax Liabilities	$(153,945)	$(153,538)
Property Related Temporary Differences	$(108,850)	$(108,276)
Amounts Due From Customers For Future Federal Income Taxes	(18,320)	(18,734)
Deferred State Income Taxes	(31,561)	(30,711)
Other (net)	4,786	4,183
Total Net Deferred Tax Liabilities	$(153,945)	$(153,538)

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 Internal Revenue Service (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 open and under audit by the IRS. During the audit the IRS agents requested a ruling from their National Office that certain interest deductions relating to corporate owned life insurance (COLI) claimed by the Company should not be allowed. The COLI program was established in 1992 as part of the Company's strategy to fund and reduce the cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1997 would reduce earnings by approximately $6 million (including interest). Management believes it has meritorious defenses and will vigorously contest any proposed adjustments. No provisions for this amount have been recorded. In the event the Company is unsuccessful it could have a material adverse impact on results of operations.

8. LEASES:

Leases of property, plant and equipment are for periods 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:

	December 31, 1997	December 31, 1996
	(in thousands)	
Operating Leases	$ 369	$ 402
Amortization of Capital Leases	3,541	2,652
Interest on Capital Leases	1,548	707
Total Rental Costs	$5,458	$3,761

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

	December 31, 1997	December 31, 1996
	(in thousands)	
Electric Utility Plant:		
Production	$ 2,000	$ 1,586
General	24,814	18,475
Total Electric Utility Plant	26,814	20,061
Accumulated Amortization	8,089	7,211
Net Properties under Capital Lease	$18,725	$12,850
Capital Lease Obligations:		
Noncurrent Liability	$15,006	$ 9,833
Liability Due Within One Year	3,719	3,017
Total Capital Lease Obligations	$18,725	$12,850

Capital lease obligations are included in other noncurrent and other current liabilities on the Balance Sheets. Properties under operating leases and related obligations are not included in the Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1997:

NOTES TO FINANCIAL STATEMENTS (Continued)

	Capital Leases	Non-cancelable Operating Leases
	(in thousands)	
1998	$ 4,859	$268
1999	4,448	196
2000	3,653	134
2001	2,932	66
2002	2,449	-
Later Years	4,377	-
Total Future Minimum Lease Payments	22,718	$664
Less Estimated Interest Element	3,993	
Estimated Present Value of Future Minimum Lease Payments	$18,725	

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9. LONG-TERM DEBT AND LINES OF CREDIT:

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

	December 31, 1997	1996
	(in thousands)	
First Mortgage Bonds	$179,410	$179,305
Senior Unsecured Notes	47,708	-
Notes Payable	75,000	75,000
Junior Debentures	38,933	38,893
Total	$341,051	$293,198

First Mortgage Bonds:		December 31, 1997	1996
% Rate	Due	(in thousands)	
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	15,000	15,000
7.90	2023 - June 1	25,000	25,000
Unamortized Discount (net)		(590)	(695)
Total		$179,410	$179,305

NOTES TO FINANCIAL STATEMENTS (Continued)

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.

In October 1997 the Company issued $48,000,000 of 6.91% Senior Unsecured Notes due October 7, 2007. The unamortized discount at December 31, 1997 is $292,000.

	December 31, 1997 (in thousands)	December 31, 1996 (in thousands)
Notes Payable to Banks:		
% 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, 1997 (in thousands)	December 31, 1996 (in thousands)
% Rate Due		
8.72 2025 - June 30	$40,000	$40,000
Unamortized Discount	(1,067)	(1,107)
Total	$38,933	$38,893

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, 1997, annual long-term debt payments are as follows:

	Amount (in thousands)
1998	$ -
1999	60,000
2000	25,000
2001	60,000
2002	25,000
Later Years	173,000
Total Principal Amount	343,000
Unamortized Discount	(1,949)
Total	$341,051

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NOTES TO FINANCIAL STATEMENTS (Continued)

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, 1997 and 1996 were available in the amounts of $442 million and $409 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, 1997:		
Commercial Paper	$36,500	6.8%
December 31, 1996:		
Notes Payable	$33,800	6.1%
Commercial Paper	17,875	6.5%
Total	$51,675	6.2%

10. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The carrying amount of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximates fair value because of the short-term maturities of these instruments. At December 31, 1997 and 1996 the fair value of long-term debt was $359 million and $304 million, respectively, based on quoted market prices for the same or similar issues and the current interest rates offered for debt of the same remaining maturities. The carrying amount for long-term debt was $341 million and $293 million at December 31, 1997 and 1996, respectively.

11. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1997 (in thousands)
Cash was paid for:	
Interest (net of capitalized amounts)	$24,490
Income Taxes	11,359
Noncash Acquisitions under Capital Leases	8,653

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spondent OWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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

Item (a)	Total (b)	Electric (c)
UTILITY PLANT		
rvice		
nt in Service (Classified)	$941,000,112	$941,000,112
perty Under Capital Leases	18,725,123	18,725,123
nt Purchased or Sold	218,671	218,671
leted Construction not Classified		
erimental Plant Unclassified		
OTAL (Enter Total of lines 3 thru 7)	$959,943,906	$959,943,906
d to Others		
for Future Use	6,862,819	6,862,819
ruction Work in Progress	32,059,799	32,059,799
sition Adjustments		
OTAL Utility Plant (Enter total of lines 8 thru 12)	$998,866,524	$998,866,524
. Prov. for Depr., Amort., & Depl.	288,229,516	288,229,516
et Utility Plant (Enter Total of line 13 less 14)	$710,637,008	$710,637,008
AIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
rvice:		
reciation	288,028,379	288,028,379
rt. and Depl. of Producing Natural Gas Land and Land Rights		
rt. of Underground Storage Land and Land Rights		
rt. of Other Utility Plant	201,137	201,137
OTAL In Service (Enter Total of lines 18 thru 21)	$288,229,516	$288,229,516
d to Others		
reciation		
rtization and Depletion		
OTAL Leased to Others (Enter Total of lines 24 and 25)		
for ure Use		
e n		
rtization		
OTAL Held for Future Use (Enter Total of lines 28 and 29)		
onment of Leases (Natural Gas)		
rt. of Plant Aquisition Adj.		
OTAL Accumulated Provisions (Should agree with line 14 above) Enter Total of lines 22,26,30,31 and 32)	$288,229,516	$288,229,516

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

ırt below the original cost of electric plant in serv-
:ing to the prescribed accounts.
on to Account 101, Electric Plant in Service
this page and the next include Account 102,
lant Purchased or Sold; Account 103, Experimental
Plant Unclassified; and Account 106, Completed
on Not Classified-Electric.
ude in column (c) or (d), as appropriate, corrections
ns and retirements for the current or preceding year.
ose in parentheses credit adjustments of plant
o indicate the negative effect of such accounts.
ify Account 106 according to prescribed ac-

counts, 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

Account (a)	Balance at Beginning of Year (b)	Addition (c)
1. INTANGIBLE PLANT		
Organization	0	0
Franchises and Consents	42,796	1,793
Miscellaneous Intangible Plant	0	0
L Intangible Plant (Enter Total of lines 2, 3, and 4)	$42,796	$1,793
2. PRODUCTION PLANT		
A. Steam Production Plant		
Land and Land Rights	1,076,545	0
Structures and Improvements	26,993,235	(238,367)
Boiler Plant Equipment	142,675,452	(3,421,072)
Engines and Engine-Driven Generators	0	0
Turbogenerator Units	55,226,269	13,786,929
Accessory Electric Equipment	12,409,590	1,139,691
Misc. Power Plant Equipment	4,838,601	865,744
. Steam Production Plant (Enter Total of lines 8 thru 14)	$243,219,692	$12,132,925
Nuclear Production Plant		
Land Rights		
Structures and Improvements		
Reactor Plant Equipment		
Turbo generator Units		
Accessory Electric Equipment		
Misc. Power Plant Equipment		
Nuclear Production Plant (Enter Total of lines 17 thru 22)		
:. Hydraulic Production Plant		
and and Land Rights		
Structures and Improvements		
eservoirs, Dams, and Waterways		
Water Wheels, Turbines, and Generators		
Accessory Electric Equipment		
Misc. Power Plant Equipment		
oads, Railroads, and Bridges		
Hydraulic Production Plant (Enter Total of lines 25 thru 31)		
. Other Production Plant		
and and Land Rights		
tructures and Improvements		
uel Holders, Products, and Accessories		
rime Movers		
enerators		
ccessory Electric Equipment		

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

reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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. In showing the clearance of 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 requirements 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 purchaser, 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.
					1
0			0	(301)	2
0			44,589	(302)	3
0			0	(303)	4
0			$44,589		5
					6
					7
0		0	1,076,545	(310)	8
101,804		29,106	26,682,170	(311)	9
3,024,973		(398,530)	135,830,877	(312)	10
0		0	0	(313)	11
4,684,964		99,000	64,427,234	(314)	12
324,810		222,815	13,447,286	(315)	13
31,903		47,609	5,720,051	(316)	14
$8,168,454		0	$247,184,163		15
					16
				(320)	17
				(321)	18
				(322)	19
				(323)	20
				(324)	21
				(325)	22
					23
					24
				(330)	25
				(331)	26
				(332)	27
				(333)	28
				(334)	29
				(335)	30
				(336)	31
					32
					33
				(340)	34
				(341)	35
				(342)	36
				(343)	37
				(344)	38
				(345)	39

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	0	0
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	0	0
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	$243,219,692	$12,132,925
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	22,148,788	309,518
45	(352) Structures and Improvements	4,924,083	291,685
46	(353) Station Equipment	60,068,680	36,670,216
47	(354) Towers and Fixtures	77,145,770	1,062,576
48	(355) Poles and Fixtures	21,060,599	2,047,111
49	(356) Overhead Conductors and Devices	79,097,077	592,875
50	(357) Underground Conduit	11,590	0
51	(358) Underground Conductors and Devices	106,066	0
52	(359) Roads and Trails	0	0
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	$264,562,653	$40,973,981
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	3,772,608	209,108
56	(361) Structures and Improvements	3,435,991	(79,468)
57	(362) Station Equipment	33,192,785	8,146,031
58	(363) Storage Battery Equipment	0	0
59	(364) Poles, Towers, and Fixtures	98,795,136	2,175,205
60	(365) Overhead Conductors and Devices	68,054,183	7,910,940
61	(366) Underground Conduit	1,787,592	288,183
62	(367) Underground Conductors and Devices	3,109,948	339,985
63	(368) Line Transfomers	68,676,628	4,829,456
64	(369) Services	17,976,090	2,636,990
65	(370) Meters	20,699,982	1,105,728
66	(371) Installations on Customer Premises	7,417,328	1,583,946
67	(372) Leased Property on Customer Premises	0	0
68	(373) Street Lighting and Signal Systems	2,265,965	40,819
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	$329,184,236	$29,186,923
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	2,366,374	29,455
72	(390) Structures and Improvements	29,802,918	804,912
73	(391) Office Furniture and Equipment	892,849	28,000
74	(392) Transportation Equipment	251,106	0
75	(393) Stores Equipment	159,597	0
76	(394) Tools, Shop and Garage Equipment	684,005	115,158
77	(395) Laboratory Equipment	414,191	0
78	(396) Power Operated Equipment	0	0
79	(397) Communication Equipment	4,478,399	(465,379)
80	(398) Miscellaneous Equipment	219,184	1,166
81	SUBTOTAL (Enter Total of lines 71 thru 80)	$39,268,623	$513,312
82	(399) Other Tangible Property	0	0
83	TOTAL General Plant (Enter Total of lines 81 and 82)	$39,268,623	$513,312
84	TOTAL (Accounts 101 and 106) (lines 5,15,23,32,41,53,69,83)	$876,278,000	$82,808,934
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)	$876,278,000	$83,027,605

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of year (g)		Line No.
			0	(346)	40
0	0		0		41
$8,168,454	0	0	$247,184,163		42
					43
0		(2,481)	22,455,825	(350)	44
11,283		(26,995)	5,177,490	(352)	45
1,020,231		(851,349)	94,867,316	(353)	46
9,923		0	78,198,423	(354)	47
205,721		70,410	22,972,399	(355)	48
85,900		62,634	79,666,686	(356)	49
0			11,590	(357)	50
0			106,066	(358)	51
0			0	(359)	52
$1,333,058		($747,781)	$303,455,795		53
					54
0		(12,375)	3,969,341	(360)	55
47,283		28,542	3,337,782	(361)	56
912,576		709,926	41,136,166	(362)	57
0			0	(363)	58
1,542,829			99,427,512	(364)	59
1,666,505		5,353	74,303,971	(365)	60
4,035			2,071,740	(366)	61
46,345			3,403,588	(367)	62
2,186,374		(74,098)	71,245,612	(368)	63
522,610			20,090,470	(369)	64
836,156		86,124	21,055,678	(370)	65
529,850			8,471,424	(371)	66
0			0	(372)	67
26,937			2,279,847	(373)	68
$8,321,500		$743,472	$350,793,131		69
					70
2,240			2,393,589	(389)	71
25,151			30,582,679	(390)	72
1,923			918,926	(391)	73
0			251,106	(392)	74
0			159,597	(393)	75
1,113			798,050	(394)	76
0			414,191	(395)	77
0			0	(396)	78
219,173		4,309	3,798,156	(397)	79
14,210			206,140	(398)	80
$263,810		$4,309	$39,522,434		81
			0	(399)	82
$263,810	0	$4,309	$39,522,434		83
$18,086,822	0	0	$941,000,112		84
			218,671	(102)	85
					86
				(103)	87
$18,086,822	0	0	$941,218,783		88

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< Page 206 Line 85 Column C >

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.

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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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				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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40				
41				
42				
43				
44				
45				
46				
47	TOTAL			$6,862,819

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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) 12/31/97	Year of Report Dec. 31, 1997

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 Demonstration (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	$2,323,417
2	PUBLIC PROJECT BLANKET	334,163
3	DISTRIBUTION CUSTOMER SERVICE BLANKET	1,016,572
4	TRANSMISSION BLANKET	1,049,441
5	GENERAL PLANT BLANKET	161,561
6	GENERAL PLANT COMMUNICATIONS BLANKET	114,685
7	WHTGSBURG AREA IMPROVEMENTS - MAYKING STATION	328,402
8	BIG SANDY U#1 LOW NOX BURNERS	950,289
9	BIG SANDY FLYASH RETENTION DAM EXTENSION	304,729
10	MICROWAVE SYSTEM REBUILD	702,234
11	DIGITAL MICROWAVE SYSTEM	1,194,749
12	BIG SANDY-INEZ PROJECT - BIG SANDY-INEZ 138KV LINE	13,489,794
13	BIG SANDY-INEZ PROJECT - BIG SANDY-138KV STATION	393,112
14	BIG SANDY-INEZ PROJECT - R/W FOR BIG SANDY-INEZ 138KV LINE	1,021,263
15	BIG SANDY-INEZ PROJECT - INEZ-JOHNS CREEK 138KV LINE	456,350
16	BIG SANDY-INEZ PROJECT - R/W FOR INEZ-JOHNS CREEK 138KV LINE	284,947
17	BIG SANDY-INEZ PROJECT - LESLIE 161KV STATION	1,608,568
18	BIG SANDY-INEZ PROJECT - INEZ 138KV STATION	1,917,658
19	BIG SANDY-INEZ PROJECT - INEZ 138KV STATION	1,759,277
20	PRESTONBURG AREA IMPROVEMENTS	1,251,036
21	WHITESBURG AREA IMPROVEMENTS - MAYKING STATION LOOP	1,104,589
22	SUPERVISORY CONTROL EQUIPMENT AT SELECTED STATIONS IN THE S.W. TRANSMISSION REGION	131,823
23	MINOR PROJECTS LESS THAN $100,000	161,140
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	$32,059,799

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CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the 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		
2	1. Kinds of Overheads	
3		
4	(A) Fossil/Hydro Generation Construction	2,806,699
5		
6		
7	(B) Transmission and Station Construction	6,851,287
8		
9		
10	(C) Energy Distribution Construction	6,370,066
11		
12	(D) Plant Capital Overheads	237,189
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
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26		
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34		
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36		
37		
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41		
42		
43		
44		
45		
46	TOTAL	$16,265,241

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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 Page 218 Footnote.1

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	S $51,142,000		
(2)	Short-Term Interest			s 5.91%
(3)	Long-Term Debt	D $291,738,000	54.53%	d 7.85%
(4)	Preferred Stock	P 0	0	p 0
(5)	Common Equity	C $243,290,000	45.47%	c 10.70%
(6)	Total Capitalization	$535,028,000	100%	
(7)	Average Construction Work In Progress Balance	W $57,686,000		

2. Gross Rate for Borrowed Funds $s(\frac{S}{W}) + d(\frac{D}{D+P+C})(1 - \frac{S}{W})$ 6.18%

3. Rate for Other Funds $[1 - \frac{S}{W}][p(\frac{P}{D+P+C}) + c(\frac{C}{D+P+C})]$ 0.55%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 5.81%

b. Rate for Other Funds - 0.19%

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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 related drafting and technical work applicable to all transmission plant and to distribution station construc-

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tion. 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 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 projects.

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

(f) See note (c) above.

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	12/31/97	Dec. 31, 1997

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 (d), 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	$279,390,269	$279,390,269		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	26,247,598	26,247,598		
4	(413) Exp. of Elec. Plt.Leas.to Others				
5	Transportation Expenses—Clearing				
6	Other Clearing Accounts	624	624		
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	$26,248,222	$26,248,222		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	(18,107,631)	(18,107,631)		
12	Cost of Removal	(3,163,537)	(3,163,537)		
13	Salvage (Credit)	3,661,068	3,661,068		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	($17,610,100)	($17,610,100)		
15	Other Debit or Cr.Items (Describe):	(12)	(12)		
16					
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$288,028,379	$288,028,379		

Section B. Balances at End of Year According to Functional Classifications

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)
18	Steam Production	126,760,523	126,760,523		
19	Nuclear Production				
20	Hydraulic Production-Conventional				
21	Hydraulic Production-Pumped Storage				
22	Other Production				
23	Transmission	76,458,634	76,458,634		
24	Distribution	73,497,063	73,497,063		
25	General	11,312,159	11,312,159		
26	TOTAL (Enter Total of lines 18 thru 25)	$288,028,379	$288,028,379		

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KENTUCKY POWER COMPANY	(1) [x] An Original (2) [ ] A Resubmission	12/31/97	Dec. 31, 1997

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 Beginning 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		2,2[illegible]
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				
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	0	$973,644

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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)	$8,806,227	$10,379,192	
2	Fuel Stock Expenses Undistributed (Account 152)	437,997	306,130	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	3,511,053	799,421	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,247,724	5,400,844	
8	Transmission Plant (Estimated)	263,329	589,690	
9	Distribution Plant (Estimated)	1,316,645	962,127	
10	Assigned to - Other	438,882	0	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	$8,777,633	$7,752,082	
12	Merchandise (Account 155)	0	0	
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	(288,049)	149,395	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$17,733,808	$18,586,799	

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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)

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	1998 No. (d)	1998 Amt. (e)
01	Balance-Beginning of Year	46,075.00	$4,638,890	0	0
02 03 04	Acquired During Year: Issued (Less Withheld Allow.)	0	0	0	0
05	Returned by EPA	0	0	0	0
06 07 08	Purchases/Transfers: Ohio Power	4,196.00	291,538	0	0
09	Natural Resource Group	663.00	332	0	0
10					
11					
12					
13					
14					
15	Total	4,859.00	$291,870	0	0
16 17 18	Relinquished During Year: Charges to Account 509	0	0	0	0
19	Other:	0	0		
20					
21 22	Cost of Sales/Transfers: Ohio Power	671.00	63,197	0	
23	Indiana Michigan Power	913.00	85,989	0	0
24					
25					
26					
27					
28	Total	1,584.00	$149,186	0	0
29	Balance-End of Year	49,350.00	$4,781,574	0	0
30 31 32	Sales: Net Sales Proceeds (Assoc. Co.)		192,021		0
33	Net Sales Proceeds (Other)		0		0
34	Gains		42,385		0
35	Losses		0		0
	Allowances Withheld (Account 158.2)				
36	Balance-Beginning of Year	0	0		
37	Add: Withheld by EPA	0	0		
38	Deduct: Returned by EPA	0	0		
39	Cost of Sales	0	0		
40	Balance-End of Year	0	0		
41 42 43	Sales: Net Sales Proceeds (Assoc. Co.)		0		
44	Net Sales Proceeds (Other)		0		
45	Gains		0		
46	Losses		0		

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Allowances (Accounts 158.1 and 158.2) (Continued)

issued allowances. Report withheld portions lines 36-40

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 acquired 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 and 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 & 43-46 the net sales proceeds and gains or losses from allowance sales.

1999		1900		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
0	0	* 25,938.00	0	657,660.00	$46,835	729,673.00	$4,685,725	01
0	0	0	0	24,935.00	0	24,935.00	0	02 03 04
0	0	0	0	0	0	0	0	05
0	0	1,291.00	193,650	9,266.00	1,130,199	14,753.00	1,615,387	06 07 08
0	0	0	0			663.00	332	09
						0	0	10
						0	0	11
						0	0	12
						0	0	13
						0	0	14
0	0	1,291.00	$193,650	9,266.00	$1,130,199	15,416.00	$1,615,719	15
						0	0	16 17 18
						0	0	19
						0	0	20
0	0					671.00	63,197	21 22
0	0					913.00	85,989	23
						0	0	24
						0	0	25
						0	0	26
						0	0	27
0	0					1,584.00	$149,186	28
0	0	27,229.00	$193,650	691,861.00	$1,177,034	768,440.00	$6,152,258	29
						0	192,021	30 31 32
						0	0	33
						0	42,385	34
						0	0	35
[redacted]								
0	0	361.00	0	17,014.00	0	17,375.00	0	36
0	0	0	0	1,440.00	0	1,440.00	0	37
0	0	0	0	0	0	0	0	38
0	0	0	0	362.00	0	362.00	0	39
0	0	361.00	0	18,092.00	0	18,453.00	0	40
	0		0			0	0	41 42 43
	0		0		45,281	0	45,281	44
	0		0		45,281	0	45,281	45
	0		0		0	0	0	46

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Represents the Year 2000.

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/97	Dec. 31, 1997

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking 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	0	VAR	$1,375,647	$69,947,535
2	Depreciation Expenses - Hanging Rock/Jefferson				
3	765 kV Line		VAR	5,208	181,849
4	Post In-Service AFUDC- Hanging Rock/Jefferson				
5	765 kV Line		406	33,408	1,166,760
6	Deferred DSM Expense	12,166,170	VAR	11,440,137	(86,757)
7	Post Employment Benefits	768,926	228	0	3,841,810
8	SFAS 109 Deferred State Income Tax	850,000	283	0	31,561,000
9	Carrying Charges - Purchased Allowances	264,422	VAR		280,149
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	$14,049,518		$12,854,400	$106,892,7

pondent ÆR COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

MISCELLANEOUS DEFERRED DEBITS (Account 186)

ort below the particulars (details) called for g llaneous Deferred debits.

r ferred debit being amortized, show period za in column (a).

3. Minor items (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.

iption of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDIT Account Charged (d)	CREDIT Amount (e)	Balance at End of Year (f)
Adjustment					
eal Estate Personal & ranchise Tax	4,920,000	5,120,000	408	4,920,000	5,120,000
					0
ctive Marketing Program s	12,013	0	401/426	12,013	0
Hot Water Tanks	0	23,882	186	473	23,409
llowances	0	514	186	105	409
rferred Emission Commiss	0	100,695		0	100,695
ed Procurement Card sactions	(39,077)	970,821	186	912,364	19,380
aneous Deferred Expenses	334	0	186/401	334	0
:ems	3,356	11,782	VAR	17,330	(2,192)
rk in Progress	1,302,531				311,619
REGULATORY COMM. S (See pages 350-351)					
	$6,199,157				$5,573,320

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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.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Interest Expense Capitalized	$1,383,774	$2,287,910
3	Contribution-In-Aid-of-Construction	1,488,649	1,676,803
4	Customer Advances	7,565	(4,928)
5	Deferred Fuel	480,361	1,267,853
6	INA Insurance Cost	737,268	968,252
7	Other	* 3,661,392	4,302,769
8	TOTAL Electric (Enter Total of lines 2 thru 7)	$7,759,009	$10,498,659
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other	* 23,159,579	23,777,571
18	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$30,918,588	$34,276,230

NOTES

* See next page.

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OTHER - LINE 17 KENTUCKY POWER COMPANY

	BEGINNING OF YEAR	END OF YEAR
Provision for Uncollectible Accounts	95,214	184,389
Tax on Accrued Payroll	12,712	0
Advance Rental Income	760	6,577
IRS Audit Settlements	575,122	410,633
Provision for Workers' Comp Costs	(2,303)	246,277
Accrued Book Pension Expense	1,323,456	1,414,239
Deferred Compensation	45,379	41,564
Accrued Vacation Pay	833,654	913,933
Management Incentive Bonus	109,756	18,899
Accrued Asbestos Lawsuit	30,654	30,654
Accrued Book Sup. Savings Plan Exp.	442	442
SFAS 106 Post Retirement Benefit	418,439	487,010
Cap. Carrying Chg-Def Book Gain-EMA	3	0
Accrued PSI Plan Expense	29,750	64,050
Book Loss Prov-Plant M&S	128,348	128,348
Tax > Book Basis - EMA	25,383	35,111
Deferred Bolivia Project Cost-Tax	31,238	0
Bk Amort Dumont Test Ctr - Norm	3,385	3,276
Accrued Companywide Incentive Plan	0	287,003
Bk Amort-Demand Side Management	0	30,364
TOTAL - LINE 7	3,661,392	4,302,769

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OTHER - LINE 17

Provision for Uncollectible Accounts - Account 190.2	70,176	88,604
SUBTOTAL	70,176	88,604
SFAS 109 Regulatory Asset - Account 190.3 & 190.4	23,089,403	23,688,967
TOTAL	23,159,579	23,777,571

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CAPITAL STOCK (Accounts 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 Exchange (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		2,000,000	$50.00	
3				
4				
5				
6				
7				
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42	TOTAL_COM	2,000,000		

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CAPITAL STOCK (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 noncumulative.

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
						7
						8
						9
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						41
1,009,000	50,450,000	0	0	0	0	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 debt 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 1997	108,750,000
6	Cash Contributions in 1997:	
7	Cash Contribution in 1997	10,000,000
8		
9		
10	Cash Contribution in 1997	10,000,000
11		
12		
13	SUBTOTAL	128,750,000
14		
15	Account 209 - Reduction in Par or Stated Value of Capital Stock	0
16		
17	Account 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	0
18		
19	Account 211 - Miscellaneous Paid-In Capital	0
20		
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40	TOTAL	$128,750,000

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LONG-TERM DEBT (Accounts 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	(KY PSC Order 95-401 dated 8-25-97 and		300,000 D
30	Registration Statement No. 333-35767 dated 9-23-97)		
31			
32			
33	TOTAL	$343,000,000	$3,735,940

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LONG-TERM DEBT (Accounts 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 amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (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) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
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	15,000,000	1,185,000	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
				220,000,000	17,525,508	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	829,200	28
						29
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				$343,000,000	$23,463,456	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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, 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)	$20,745,738
2	Reconciling Items for the Year	
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	* 28,097,640
28	Show Computation of Tax:	
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Income for the Year (Page 117)		20,745,738
Total Federal Income Taxes		9,414,761
Pre-Tax Book Income		30,160,499
Incr (Decr) in Taxable Income Resulting From:		
Excess of Tax Over Book Depreciation		(2,258,374)
Allowance for Funds Used During Construction & Miscellaneous Items Capitalized on the Books but Deducted for Tax Purposes		1,329,652
Removal Cost		(2,400,000)
Deferred Fuel		(1,304,170)
Charges to Clearing Accounts (Net)		173,670
Reserve for Self Insurance (Net)		658,031
Uncollectible Accounts (Net)		254,788
Deferred Compensation (Net)		(33,877)
Uncollectible Accounts (Net) - O.I.D.		52,601
Vacation Pay (Net)		641,683
Accrued Mgt. Incentive Bonus		(196,408)
Accrued Companywide Incentive Plan		819,997
Pension Trust Expense		424,451
Demand Side Management		(726,033)
Advance Rental (Net)		16,620
Excess Tax Versus Book Gain		373,863
Emission Allowances (Net)		(281,910)
Loss on Reacquired Debt (Net)		136,964
Non Deductible Meals, Travel, and Memberships		313,858
Corporate Owned Life Insurance		(938,687)
Post Retirement Benefits		1,075,610
Fed Environmental Excise Tax		(26,000)
Amort IRS Settlements		(169,188)
Federal Tax Net Income - Estimated Current Year Taxable Income		28,097,640
Show Computation of Tax:		
Federal Income Tax on Current Taxable Income (Seperate Return Basis) at Statutory Rate of 35%		9,834,174
Adjustment Due to System Consolidation	(a)	(76,456)
Estimated Currently Payable	(b)	9,757,718
Adjustments of Prior Year Accruals (Net)		308,485
Estimated Current Federal Income Tax Expense		10,066,203

(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.

(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 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 1997 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed in September, 1998. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until October, 1998.

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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)	Adjustments (f)
1	FEDERAL					
2	Taxes on Income	(879,417)		10,066,203	10,193,337	
3						
4	Unemployment Ins. - 1996	2,741		0	0	
5	Unemployment Ins. - 1997			44,280	44,163	
6						
7	Ins. Contrib. Act 1996	67,706			0	
8	Ins. Contrib. Act - 1997			2,840,416	2,809,876	
9						
10	Env. Excise Tax 1996	(9,032)		(26,000)	(35,032)	
11	Env. Excise Tax 1997			0	0	
12						
13	STATE OF KENTUCKY					
14	Taxes on Income	(478,187)		2,189,761	1,165,000	
15	City of Morehead Tax			0	0	
16	PSC Maint. Rem. Asst. 1997		166,536	368,302	403,528	
17						
18	Unemp. Ins. - 1996	1,347		0	0	
19	Unemp. Ins. - 1997			23,769	23,826	
20						
21	Intang. Prop. Tax - 1997			0	0	
22						
23	Real & Pers. Prop 1993	61,356		0	0	
24	Real & Pers. Prop 1995	75,000		62,307	137,307	
25	Real & Pers. Prop 1996	1,301,239		93,300	1,252,917	
26	Real & Pers. Prop 1997	4,920,000		0	3,760,263	
27	Real & Pers. Prop 1998			5,120,000	0	
28						
29	Real & Pers. Prop.(FRECO)1996			0	0	
30	Real & Pers. Prop.(FRECO)1997	1,074		30,000	26,871	
31						
32	STATE OF INDIANA					
33	Taxes on Income			0	0	
34						
35	STATE OF WEST VIRGINIA					
36	Taxes on Income	265		0	265	
37						
38	Business Franchise Tax - 1996	90		(90)	0	
39	Business Franchise Tax - 1997			390	390	
40	Unemployment Ins. - 1997			10,059	9,755	
41	TOTAL	$5,064,182	$166,536	$20,822,697	$19,792,466	0

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than 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 footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Report in columns (i) through (l) how the taxes were distributed. Report in column (i) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show 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				
(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)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
(1,006,551)		10,425,322			* (359,119)	2
						3
2,741		0			0	4
117		27,641			16,639	5
						6
31,387		0			0	7
66,859		1,653,956			1,186,460	8
						9
0		(26,000)			0	10
0		0			0	11
						12
						13
546,574		2,274,411			(84,650)	14
0		0			0	15
	201,762	368,302			0	16
						17
1,347		0			0	18
(57)		22,570			1,199	19
						20
0		0			0	21
						22
61,356		0			0	23
0		62,307			0	24
141,623		0			93,300	25
1,159,737		4,920,000			(4,920,000)	26
5,120,000		93,300			5,026,700	27
						28
1,074		0			0	29
3,129		0			30,000	30
						31
						32
0		0			0	33
						34
						35
0		0			0	36
						37
0		0			(90)	38
0		300			90	39
304		0			10,059	40
$6,129,640	$201,762	$19,822,109	0	0	$1,000,588	41

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KENTUCKY POWER COMPANY

DETAIL OF PAGE 263, COLUMN L

Line	TOTAL	408.2 & 409.2	EMPLOYMENT TAXES*	PROPERTY TAXES*	OTHER
2	(359,119)	(359,119)			
5	16,639		16,639		
8	1,186,460		1,186,460		
14	(84,650)				(84,650)
19	1,199		1,199		
24	93,300			93,300	
26	(4,920,000)			(4,920,000)	
27	5,026,700			5,026,700	
30	30,000	30,000			
38	(90)				(90)
39	90				90
40	10,059				10,059
	1,000,588	(329,119)	1,204,298	200,000	(74,591)

DISTRIBUTION OF EMPLOYEMENT TAXES

ACCOUNT	AMOUNT
107	821,779
108	65,203
152	71,837
163	126,132
184	74,557
186	44,790

DISTRIBUTION OF PROPERTY TAXES

ACCOUNT	AMOUNT
186	200,000

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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 Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	1,400,931			411.4	146,200	* (7,340)
4	7%						
5	10%	15,606,193			411.4	1,073,180	* (165,575)
6							
7							
8	TOTAL	$17,007,124				$1,219,380	($172,915)
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTALS)						
10							
11							
12							
13							
14							
15							
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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
0			3
1,247,391	30 Yrs.		4
			5
14,367,438	30 Yrs.		6
			7
$15,614,829			8
			9
			10
			11
			12
			13
			14
			15
			16
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KENTUCKY POWER COMPANY

*Adjustment of Prior Years' Federal Income Tax Returns

Account 411.5 (7,340)

< Page 266 Line 5 Column G >

*Adjustment of Prior Year's Federal Income Tax Return

Account 411.5 (165,575)

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ondent ER COMPANY	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

OTHER DEFERRED CREDITS (Account 253)

ort below the particulars (details) called for i her deferred credits.
r deferred credit being amortized, show the 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.

Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
are - Customer Donations	$1,055	VAR	$391	$6,164	$6,828
Rent Prepayments - roperty	1,210		0	16,620	17,830
ified OTC Payments	112	186	116	4	0
ed Checks	(150)		0	150	0
Sales	0	186/253	86,691	86,690	(1)
ative Options	0			149,034	149,034
Conservancy	53,550	234	57,375	3,825	0
TOTAL	$55,777		$144,573	$262,487	$173,691

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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) 12/31/97	Year of Report Dec. 31, 1997

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

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

Line No.	Account Subdivisions (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	$76,574,722	$5,820,235	$3,570,427
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)	$76,574,722	$5,820,235	$3,570,427
6	Other (Specify) Accum DFIT-Other Property	17,914		
7	SFAS 109	40,904,029		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$117,496,665	$5,820,235	$3,570,427
10	Classification of TOTAL			
11	Federal Income Tax	117,496,665	5,820,235	3,570,427
12	State Income Tax			
13	Local Income Tax			

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

and deductions.

x s as required.

ES NG YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
to .2	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
[redacted]							1
						$78,824,530	2
							3
							4
						$78,824,530	5
						17,914	6
		182/254	400,065			40,503,964	7
							8
						$119,346,408	9
[redacted]							10
			400,065			119,346,408	11
							12

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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/97	Dec. 31, 1997

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	$80,634	$2,828,090	$1,584,139
4	Clearing Accounts	92,598	1,172,788	1,233,572
5	Post Retirement Benefits	8	0	0
6	Loss on Reacquisition of Debt	306,377	0	47,944
7	Emission Allowances	57,070	24,720	8,872
8	Other	0	0	0
9	TOTAL Electric (Total of lines 3 thru 8)	$536,687	$4,025,598	$2,874,527
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)	0	0	0
18	Other (Specify) SFAS 109	66,423,067	0	0
19	TOTAL (Acct 283) (Enter Total of lines 9,17 and 18)	$66,959,754	$4,025,598	$2,874,527
20	Classification of TOTAL			
21	Federal Income Tax	36,248,754	4,025,598	2,874,527
22	State Income Tax	30,711,000		
23	Local Income Tax			

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

income and deductions.

3. Provide in the space below explanations for page 276 and 277. Include amounts relating to insignificant items listed under Other.

4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credits to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						$1,324,585	3
						31,814	4
						8	5
						258,433	6
98,052						170,970	7
						0	8
$98,052						$1,785,810	9
							10
						0	11
						0	12
						0	13
						0	14
						0	15
						0	16
						0	17
		182/254	183,973	182	850,000	67,089,094	18
$98,052			$183,973		$850,000	$68,874,904	19
							20
98,052			183,973			37,313,904	21
					850,000	31,561,000	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 ratemaking 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 (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	SFAS 109 Deferred Federal Income Taxes	190	$608,410	$986,322	$9,535,589
2					
3	Excess of Base Fuel Cost Deferred - Credit	401	13,450,212	12,488,583	135,735
4					
5	Excess of Base Fuel Cost Deferred -				
6	Accrued Utility Revenues Credit	401	1,724,941	1,382,400	(297,832)
7					
8	SFAS 109 Excess Deferred Federal Income Taxes	VAR	569,957	0	8,068,855
9					
10	Deferred Emission Allowance Gains	VAR	0	42,835	42,835
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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37					
38					
39					
40					
41	TOTAL		$16,353,520	$14,900,140	$17,485,182

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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) 12/31/97	Year of Report Dec. 31, 1997

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	$105,917,091	$106,441,290
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	58,679,922	58,416,959
5	Large (or Ind.) (See Instr.4)	94,644,445	92,322,561
6	(444) Public Street and Highway Lighting	863,808	845,597
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	$260,105,266	$258,026,407
11	(447) Sales for Resale	$89,336,603	$57,140,792
12	TOTAL Sales of Electricity	* $349,441,869	$315,167,199
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	$349,441,869	$315,167,199
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$1,363,157	$1,410,848
17	(451) Miscellaneous Service Revenues	413,800	113,552
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,315,284	735,901
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,009,239	5,893,376
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$10,101,480	$8,153,677
27	TOTAL Electric Operating Revenues	$359,543,349	$323,320,876

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ELECTRIC OPERATING REVENUES (Account 400)(Continued)

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 increases 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 No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
2,196,748	2,190,616	142,198	140,844	2
				3
1,165,684	1,150,454	23,691	23,048	4
3,141,795	3,076,374	1,690	1,711	5
10,313	9,909	476	467	6
				7
				8
				9
6,514,540	6,427,353	168,055	166,070	10
5,893,932	3,680,301	66	57	11
12,408,472	10,107,654	168,121	166,127	12
				13
12,408,472	10,107,654	168,121	166,127	14

Line 12, Column (b) includes $ 4,806,094 of unbilled revenues.
Line 12, Column (d) includes 116,626 MWH relating to unbilled revenues.

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KENTUCKY POWER COMPANY

Unmetered Sales Included in Service:

	440	442	444
Customers	29,650	5,151	24
Revenues	2,209,483	880,610	7,291
MWH Sales (Estimated)	21,141	9,902	49

Page 300-301 Footnote.1

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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," pages 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	2,115,542	101,237,789	141,996	14,898	4.7854¢
3	RS-LM-TOD	7,034	205,191	200	35,170	2.9171¢
4	RS-TOD	38	1,053	1	38,000	2.7710¢
5	OL	21,141	2,209,483 *			10.4511¢
6	SGS	(5)	(320)	3	(1,666)	6.4000¢
7	UNBILLED REVENUE	52,998	2,263,895			4.2716¢
8	TOTAL RESIDENTIAL	2,196,748	105,917,091	142,198	15,448	4.8215¢
9						
10	442 - COMMERCIAL AND INDUSTRIAL					
11	SGS	60,982	4,735,396	13,960	4,368	7.7652¢
12	MGS	554,816	31,132,786	10,470	52,991	5.6113¢
13	MGS-TOD	1,280	58,388	32	40,000	4.5615¢
14	LGS	749,027	32,763,316	796	940,988	4.3741¢
15	LGS-LM-TOD	2,184	75,407	6	364,000	3.4527¢
16	IRP	175,716	4,463,441	1	175,716,000	2.5401¢
17	QP	884,389	29,206,135	74	11,951,202	3.3024¢
18	CIP-TOD	1,792,837	46,928,640	12	149,403,083	2.6175¢
19	MW	12,810	542,823	29	441,724	4.2374¢
20	OL	9,902	880,610			8.8932¢
21	RS	4	157	1	4,000	3.9250¢
22	UNBILLED REVENUE	63,532	2,537,268			3.9936¢
23	TOTAL COMMERCIAL AND INDUSTRIAL	4,307,479	153,324,367	25,381	169,712	3.5594¢
24						
25	444 - PUBLIC ST. & HWY LIGHTING					
26	SGS	1,990	145,401	405	4,913	7.3065¢
27	MGS	624	34,197	15	41,600	5.4802¢
28	SL	7,583	672,828	56	135,410	8.8728¢
29	OL	49	7,291			14.8795¢
30	UNBILLED REVENUE	67	4,091			6.1059¢
31	TOTAL PUBLIC ST. & HWY LIGHTING	10,313	863,808	476	21,665	8.3759¢
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed	6,397,944	$255,300,012	168,066	38,068	3.9903¢
42	Total Unbilled Rev.(See Instr. 6)	116,597	$4,805,254			4.1212¢
43	TOTAL	6,514,540	$260,105,266	168,055	38,764	3.9926¢

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

LF - for long-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 seller 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 desgnated 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	City of Hamilton	RQ	OPCo 96	0	0	0
2	City of Olive Hill	RQ	KPCo 13	5.1	5.1	5.1
3	City of Vanceburg	RQ	KPCo 18	10.0	10.0	10.0
4	SUBTOTAL-RQ					
5						
6	Indianapolis P&L	LF	IMPCo 21	N/A	N/A	N/A
7	NCEMC	LF	APCo 135	N/A	N/A	N/A
8	AMP Ohio	LF	OPCo 74	N/A	N/A	N/A
9						
10	Indianapolis P&L	IF	IMPCo 21	N/A	N/A	N/A
11						
12	Amp Ohio	SF	OPCo 74	N/A	N/A	N/A
13	Cleveland Public Pwr	SF	* Note 1	N/A	N/A	N/A
14	Edison Sault Elec	SF	Note 1	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

	REVENUE				
Megawatthours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
0	0	$2,700		$2,700	1
26,849	550,135	893,434	2,040	1,445,609	2
51,904	872,449	1,523,678	13,320	2,409,447	3
78,753	1,422,584	2,419,812	15,360	3,857,756	4
					5
1,931	153,187	30,619	* 88,784	272,590	6
115,460	780,718	1,774,962	377,457	2,933,137	7
44,614	785,994	734,045	182,497	1,702,536	8
					9
1,199		17,806		17,806	10
					11
5,814	20,738	80,687	17,498	118,923	12
14,241	114,751	228,176	63,624	406,551	13
8,760	34,709	182,668	29,857	247,234	14

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SALES FOR RESALE (Account 447)

-t sales for resale (i.e., sales to purchasers n ate consumers) transacted on a settlement er than power exchanges during the year. Do not xchanges of electricity (i.e., transactions a balancing of debits and credits for energy, etc.) and any settlements for imbalanced exchanges chedule. Power exchanges must be reported on the Power schedule (page 326-327).

r the name of the purchaser in column (a). Do note e or truncate the name or use acronyms. Explain in ite any ownership interest or affiliation the it has with the purchaser.

column (b), enter a Statistical Classification Code the original contractual terms and conditions of ice as follows:

r requirements service. Requirements service is which the supplier plans to provide on an ongoing .e., the supplier includes projected load for this in its system resource planning). In addition, the ity of requirements service must be the same as, or nly to, the supplier's service to its own ultimate s.

or long-term service. "Long-term" means five years er 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 seller 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 desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

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)
ne	LU	APCo 24	N/A	N/A	N/A
ia & Pwr	LU	APCo 16	N/A	N/A	N/A
:	OS	Note 1	N/A	N/A	N/A
f. - Assoc. Co.	OS	APCo 20	N/A	N/A	N/A
ower, Inc.	OS	Note 1	N/A	N/A	N/A
ading Corp.	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
N	OS	Note 1	N/A	N/A	N/A
iio	OS	OPCo 74	N/A	N/A	N/A
Power Corp.	OS	Note 1	N/A	N/A	N/A
iated Electric Coop	OS	Note 1	N/A	N/A	N/A
iergy	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
0			$474,170	$474,170	1
11,026	455,216	184,413	787,680	1,427,309	2
				0	3
1,745		46,250	559	46,809	4
3,637,443		41,046,277	0	41,046,277	5
3,960		120,096	802	120,898	6
22,296		680,943	6,667	687,610	7
2,259		50,096	0	50,096	8
1,182		48,192	0	48,192	9
2,987		85,558	33,616	119,174	10
20,777		564,398	4,500	568,898	11
54		1,102	0	1,102	12
6,100		141,789	3,551	145,340	13
1,560		35,626	0	35,626	14

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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) 12/31/97	Year of Report Dec. 31, 1997

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for long-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 seller 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 desgnated 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	Carolina P&L	OS	APCo 24	N/A	N/A	N/A
2	Catex-Vitol Electric	OS	Note 1	N/A	N/A	N/A
3	Central Illinois PS	OS	IMPCo 67	N/A	N/A	N/A
4	Central Louisianna Electric	OS	Note 1	N/A	N/A	N/A
5	CILMAR	OS	Note 1	N/A	N/A	N/A
6	Cincinnati	OS	OPCo 21	N/A	N/A	N/A
7	Citizens-Lehman Pwr	OS	Note 1	N/A	N/A	N/A
8	City of Cleveland	OS	Note 1	N/A	N/A	N/A
9	Cleveland Electric Illum	OS	OPCo 31	N/A	N/A	N/A
10	CMS	OS	Note 1	N/A	N/A	N/A
11	CNG Energy Services	OS	Note 1	N/A	N/A	N/A
12	Commonwealth Edison	OS	IMPCo 20	N/A	N/A	N/A
13	Conagra Energy	OS	Note 1	N/A	N/A	N/A
14	Consumers Power	OS	IMPCo 68	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
11,038		$289,251	$15,110	$304,361	1
18,707		532,615	1,252	533,867	2
1,289		29,428	9,607	39,035	3
108		2,514	0	2,514	4
113		1,748	189	1,937	5
15,209		346,680	12,631	359,311	6
50,819		1,219,735	34,158	1,253,893	7
2,826		73,333	10,718	84,051	8
1,853		46,654	6,847	53,501	9
3,861		87,139	1,622	88,761	10
11,127		258,790	483	259,273	11
113,520		2,509,095	378,938	2,888,033	12
3,817		102,684	0	102,684	13
110,817		2,488,776	261,268	2,750,044	14

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

LF - for long-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 seller can unilaterally get out of the contract.

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Coral Power	OS	Note 1	N/A	N/A	N/A
2	CPS	OS	Note 1	N/A	N/A	N/A
3	Dayton P&L	OS	OPCo 36	N/A	N/A	N/A
4	Del	OS	Note 1	N/A	N/A	N/A
5	Delhi Energy Serv.	OS	Note 1	N/A	N/A	N/A
6	Duke	OS	APCo 18	N/A	N/A	N/A
7	Dupont	OS	Note 1	N/A	N/A	N/A
8	Duquesne	OS	OPCo 33	N/A	N/A	N/A
9	East	OS	Note 1	N/A	N/A	N/A
10	Eastex Power Market	OS	Note 1	N/A	N/A	N/A
11	ECI	OS	Note 1	N/A	N/A	N/A
12	EKPCC	OS	KPCo 14	N/A	N/A	N/A
13	Electric Clearinghouse	OS	Note 1	N/A	N/A	N/A
14	Enerz	OS	Note 1	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
9,937		$261,712	$1,748	$263,460	1
7,778		169,682	4,328	174,010	2
5,487		129,400	11,393	140,793	3
2,901		83,892	0	83,892	4
6,548		142,254	2,872	145,126	5
6,533		136,879	14,159	151,038	6
18,767		467,719	0	467,719	7
8,625		219,513	18,397	237,910	8
11,938		289,496	0	289,496	9
13,238		315,696	108	315,804	10
7,480		163,280	63,910	227,190	11
466		12,833	1,272	14,105	12
33,545		795,570	1,407	796,977	13
1,560		33,109	0	33,109	14

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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) 12/31/97	Year of Report Dec. 31, 1997

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Engage	OS	Note 1	N/A	N/A	N/A
2	Engelhard Power Mkt	OS	Note 1	N/A	N/A	N/A
3	Enron Power Market	OS	Note 1	N/A	N/A	N/A
4	Entergy	OS	Note 1	N/A	N/A	N/A
5	EPI	OS	Note 1	N/A	N/A	N/A
6	Federal Energy Sales	OS	Note 1	N/A	N/A	N/A
7	General Public Utilities	OS	Note 1	N/A	N/A	N/A
8	Heartland Energy Svc	OS	Note 1	N/A	N/A	N/A
9	Illinois Power	OS	IMPCo 23	N/A	N/A	N/A
10	Illnova	OS	Note 1	N/A	N/A	N/A
11	IMPA	OS	IMPCo 74	N/A	N/A	N/A
12	Indianapolis P&L	OS	IMPCo 21	N/A	N/A	N/A
13	Kentucky Utilities	OS	OPCo 22	N/A	N/A	N/A
14	Koch Power Service	OS	Note 1	N/A	N/A	N/A

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
6,533		$155,850	$118	$155,968	1
4,411		106,889	0	106,889	2
155,349		4,040,920	33,663	4,074,583	3
18,825		534,969	3,187	538,156	4
5,377		121,591	0	121,591	5
605		15,040	1,515	16,555	6
323		10,752	0	10,752	7
512		13,063	898	13,961	8
24,879		596,650	55,157	651,807	9
9		143	0	143	10
20,731		374,926	80,676	455,602	11
585		21,719	1,765	23,484	12
51		4,795	177	4,972	13
29,850		669,879	48,128	718,007	14

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

LF - for long-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 seller 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 desgnated 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	LG&E Power Market	OS	Note 1	N/A	N/A	N/A
2	Louis Dreyfus Elec Pwr	OS	Note 1	N/A	N/A	N/A
3	Louisville Gas & Elec	OS	IMPCo 79	N/A	N/A	N/A
4	Michigan Pub Pwr Agency	OS	Note 1	N/A	N/A	N/A
5	Mid Con Pwr Serv	OS	Note 1	N/A	N/A	N/A
6	Morgan Stanley Group	OS	Note 1	N/A	N/A	N/A
7	MREI	OS	Note 1	N/A	N/A	N/A
8	NAEC	OS	Note 1	N/A	N/A	N/A
9	NESI	OS	Note 1	N/A	N/A	N/A
10	NIPSCO	OS	IMPCo 22	N/A	N/A	N/A
11	Noram Energy Serv	OS	Note 1	N/A	N/A	N/A
12	NPE	OS	Note 1	N/A	N/A	N/A
13	NY State Electric & Gas	OS	Note 1	N/A	N/A	N/A
14	Ohio Edison	OS	OPCo 25	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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 (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On seperate 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
14,369		$332,391	$2,616	$335,007	1
24,579		610,134	4,534	614,668	2
2,364		96,488	2,221	98,709	3
2,572		46,553	6,710	53,263	4
6,397		161,074	1,447	162,521	5
4,042		102,337	2,556	104,893	6
15,196		356,741	377	357,118	7
754		23,787	0	23,787	8
11,266		268,813	2,846	271,659	9
933		32,616	4,264	36,880	10
9,378		230,424	2,298	232,722	11
18,356		478,884	168	479,052	12
4,786		115,875	0	115,875	13
2,160		58,735	6,796	65,531	14

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

LF - for long-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 seller 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 desgnated 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	OVEC	OS	APCo 22	N/A	N/A	N/A
2	PAC	OS	Note 1	N/A	N/A	N/A
3	Pan Energy	OS	Note 1	N/A	N/A	N/A
4	PECO Energy, Inc.	OS	Note 1	N/A	N/A	N/A
5	Pennsylvania P&L	OS	Note 1	N/A	N/A	N/A
6	Phibro, Inc.	OS	Note 1	N/A	N/A	N/A
7	PJM PL	OS	Note 1	N/A	N/A	N/A
8	Plum	OS	Note 1	N/A	N/A	N/A
9	Power Co. of America	OS	Note 1	N/A	N/A	N/A
10	Proliance Energy	OS	Note 1	N/A	N/A	N/A
11	PS of Indianna	OS	INPCo 24	N/A	N/A	N/A
12	PSEG	OS	Note 1	N/A	N/A	N/A
13	QST	OS	Note 1	N/A	N/A	N/A
14	Rainbow Energy Mkt	OS	Note 1	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
355		$12,724	$339	$13,063	1
36,543		875,228	2,635	877,863	2
256		5,358	964	6,322	3
134,508		2,193,276	420,196	2,613,472	4
8,569		222,898	290	223,188	5
2,258		55,656	0	55,656	6
2,904		83,792	0	83,792	7
3,173		78,190	0	78,190	8
14,610		344,717	910	345,627	9
107		2,823	0	2,823	10
40		4,046	178	4,224	11
11,529		290,545	601	291,146	12
1,399		32,512	0	32,512	13
320		7,536	942	8,478	14

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SALES FOR RESALE (Account 447)

...ll sales for resale (i.e., sales to purchasers ...timate consumers) transacted on a settlement ...ther than power exchanges during the year. Do not ... exchanges of electricity (i.e., transactions ...ng a balancing of debits and credits for energy, ...y,etc.) and any settlements for imbalanced exchanges ... schedule. Power exchanges must be reported on the ...ed Power schedule (page 326-327).

...ter the name of the purchaser in column (a). Do note ...ate or truncate the name or use acronyms. Explain in ...note any ownership interest or affiliation the ...ent has with the purchaser.

... column (b), enter a Statistical Classification Code ...n the original contractual terms and conditions of ...vice as follows:

...for requirements service. Requirements service is ... which the supplier plans to provide on an ongoing ...i.e., the supplier includes projected load for this ... in its system resource planning). In addition, the ...lity of requirements service must be the same as, or ...only to, the supplier's service to its own ultimate ...rs.

...for long-term service. "Long-term" means five years ...ger 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 seller 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.

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...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)
...nd	OS	IMPCo 70	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
	OS	OPCo 74	N/A	N/A	N/A
...Power Market	OS	Note 1	N/A	N/A	N/A
...rn Energy Market	OS	Note 1	N/A	N/A	N/A
...n	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
...Edison	OS	OPCo 35	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
	OS	APCo 52	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A
	OS	Note 1	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1		$125	$10	$135	1
70		1,246	243	1,489	2
28		6,910	1,394	8,304	3
12,894		369,842	8,139	377,981	4
51,558		1,242,533	5,908	1,248,441	5
8,309		333,928	0	333,928	6
497		13,123	486	13,609	7
387		8,163	1,292	9,455	8
3,442		81,029	0	81,029	9
15,093		393,318	44,845	438,163	10
581		17,272	1,351	18,623	11
3,763		108,721	0	108,721	12
12,316		296,994	0	296,994	13
269		7,516	0	7,516	14

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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) 12/31/97	Dec. 31, 1997

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for long-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 seller can unilaterally get out of the contract.

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IU - for intermediate-term service from a desgnated 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	Virginia Electric & Pwr	OS	APCo 16	N/A	N/A	N/A
2	Wabash	OS	IMPCo 76	N/A	N/A	N/A
3	West Penn Power	OS	OPCo 73	N/A	N/A	N/A
4	Western Power Serv	OS	Note 1	N/A	N/A	N/A
5	WILL	OS	Note 1	N/A	N/A	N/A
6	Wisconsin Elec Pwr	OS	Note 1	N/A	N/A	N/A
7	Wisconsin Power Co.	OS	Note 1	N/A	N/A	N/A
8	AES Power, Inc.	OS	Note 1	N/A	N/A	N/A
9	Carolina P&L	OS	Note 1	N/A	N/A	N/A
10	Catex-Vitol	OS	Note 1	N/A	N/A	N/A
11	Citizens-Lehmen Power	OS	Note 1	N/A	N/A	N/A
12	Koch Power Service	OS	Note 1	N/A	N/A	N/A
13	PECO Energy, Inc.	OS	Note 1	N/A	N/A	N/A
14	PHIBRO, Inc.	OS	Note 1	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

	REVENUE				
Megawatthours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
15,860		$405,682	$4,913	$410,595	1
3,509		127,532	132	127,664	2
1,710		43,224	4,629	47,853	3
362		8,616	611	9,227	4
14,068		405,786	133	405,919	5
32,898		726,214	77,503	803,717	6
355		(6,184)	936	(5,248)	7
409,776		0	* 3,150,201	3,150,201	8
2,934		0	14,017	14,017	9
0		0	876	876	10
42,211		0	270,101	270,101	11
114,151		0	902,322	902,322	12
78,339		0	779,013	779,013	13
4,720		0	43,462	43,462	14

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

LF - for long-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 seller 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	SUBTOTAL-NON-RQ					
2						
3	TOTAL					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						

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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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
5,815,179	$2,345,313	$75,646,109	$8,925,368	$86,916,790	1
					2
5,893,932	3,767,897	78,065,921	8,940,728	90,774,546	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14

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< Page 310 Line 13 Column c >

Note 1 - AEP Power Sales Tariff, AEP companies FERC Electric Tariff Original Volume 2

< Page 311 Line 6 Column j >

Page 311, Line 6 through page 311.8, Line 7 represent transmission and ancillary charges associated with account 447.

< Page 311.8 Line 8 Column j >

Page 311.8, Line 8 through Page 311.8, Line 14 represent coal conversion services and related transmission and ancillary revenues.

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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	$2,811,684	$2,572,976
5	(501) Fuel	* 77,051,102	67,697,233
6	(502) Steam Expenses	2,580,010	2,745,938
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred--Cr.		
9	(505) Electric Expenses	304,160	214,104
10	(506) Miscellaneous Steam Power Expenses	2,166,771	2,055,334
11	(507) Rents	7,491	9,945
12	(509) Allowance	0	(264,640)
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$84,921,218	$75,030,890
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$2,018,601	$2,315,536
16	(511) Maintenance of Structures	1,109,889	1,639,879
17	(512) Maintenance of Boiler Plant	5,350,664	11,649,423
18	(513) Maintenance of Electric Plant	925,038	2,200,845
19	(514) Maintenance of Miscellaneous Steam Plant	612,154	828,591
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$10,016,346	$18,634,274
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$94,937,564	$93,665,164
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred--Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses--Nuclear Power (Enter total of lines 33 and 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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ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

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(Enter total of lines 50 and 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 Total of lines 67 and 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$113,938,338	$96,484,586
77	(556) System Control and Load Dispatching	1,129,986	887,88
78	(557) Other Expenses	0	76
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$115,068,324	$97,372,544
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$210,005,888	$191,037,708
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$1,332,568	$1,045,683
84	(561) Load Dispatching	271,868	233,223
85	(562) Station Expenses	225,250	232,250
86	(563) Overhead Lines Expenses	126,640	183,002
87	(564) Underground Lines Expenses	0	0
88	(565) Transmission of Electricity by Others	(2,414,545)	(3,041,968)
89	(566) Miscellaneous Transmission Expenses	391,649	751,170
90	(567) Rents	(73,670)	1,729
91	TOTAL Operation (Enter Total of lines 83 thru 90)	($140,240)	($594,911)
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$382,315	$233,318
94	(569) Maintenance of Structures	68,242	42,957
95	(570) Maintenance of Station Equipment	524,459	1,143,491
96	(571) Maintenance of Overhead Lines	1,150,547	858,521
97	(572) Maintenance of Underground Lines	9,887	0
98	(573) Maintenance of Miscellaneous Transmission Plant	14,393	52,414
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$2,149,843	$2,330,701
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$2,009,603	$1,735,790
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$2,383,044	$1,180,294

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount For Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	$236,314	$129,644
106	(582) Station Expenses	120,188	196,527
107	(583) Overhead Line Expenses	538,307	290,801
108	(584) Underground Line Expenses	12,691	13,832
109	(585) Street Lighting and Signal System Expenses	18,944	43,851
110	(586) Meter Expenses	971,124	993,478
111	(587) Customer Installations Expenses	465,980	312,126
112	(588) Miscellaneous Expenses	2,422,313	2,606,434
113	(589) Rents	350,210	369,568
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$7,519,115	$6,136,555
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$691,567	$523,491
117	(591) Maintenance of Structures	88,847	48,502
118	(592) Maintenance of Station Equipment	412,030	562,259
119	(593) Maintenance of Overhead Lines	7,709,592	7,584,978
120	(594) Maintenance of Underground Lines	149,049	132,218
121	(595) Maintenance of Line Transformers	739,045	845,170
122	(596) Maintenance of Street Lighting and Signal Systems	46,759	144,362
123	(597) Maintenance of Meters	171,274	243,632
124	(598) Maintenance of Miscellaneous Distribution Plant	300,536	232,475
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$10,308,699	$10,317,087
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$17,827,814	$16,453,642
127	4.CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	$330,622	$476,997
130	(902) Meter Reading Expenses	1,615,992	1,617,851
131	(903) Customer Records and Collection Expenses	4,609,202	4,345,986
132	(904) Uncollectible Accounts	1,496,337	1,507,734
133	(905) Miscellaneous Customer Accounts Expenses	378,391	405,100
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$8,430,544	$8,353,668
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$330,594	$388,983
138	(908) Customer Assistance Expenses	2,920,704	3,290,795
139	(909) Information and Instructional Expenses	18,173	40,331
140	(910) Miscellaneous Customer Service and Information Expenses	573,709	1,061,725
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$3,843,180	$4,781,834
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	3,072	3,261
146	(913) Advertising Expenses	82,763	112,651
147	(916) Miscellaneous Sales Expenses	324,067	419,786
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$409,902	$535,698
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$4,089,958	$4,503,868
152	(921) Office Supplies and Expenses	4,240,926	4,452,493
153	(Less) (922) Administrative Expenses Transferred--Credit	9,694	128

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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	$668,934	$559,931
156	(924) Property Insurance	277,569	299,471
157	(925) Injuries and Damages	3,620,440	2,814,495
158	(926) Employee Pensions and Benefits	6,487,247	6,946,867
159	(927) Franchise Requirements	118,501	117,020
160	(928) Regulatory Commission Expenses	281,285	296,567
161	(929) (Less) Duplicate Charges--Cr.		
162	(930.1) General Advertising Expenses	* 213,681	151,974
163	(930.2) Miscellaneous General Expenses	2,270,774	973,170
164	(931) Rents	267,509	1,721
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$22,527,130	$21,117,449
166	Maintenance		
167	(935) Maintenance of General Plant	$1,941,956	$1,510,948
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$24,469,086	$22,628,397
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	$266,996,017	$245,526,737

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 personel, include such employees 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 dete mined 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)	12/31/97
2. Total Regular Full-Time Employees	729
3. Total Part-Time and Temporary Employees	2
4. Total Employees	731

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< Page 320 Line 5 Column B >

ACCOUNT 50199

Includes a credit pertaining to Deferred Fuel Costs of $1,305,170 applicable to the current year.

< Page 323 Line 162 Column 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 1997 $140,964 was related to advertising as usualy defined and $72,717 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. lso 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 projected 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP Generating Co. (3)	* RQ	AEG 1	N/A	N/A	N/A
2			(2)			
3						
4	Indianapolis Power & Light	IF	IMPCO 21	N/A	N/A	N/A
5						
6	Tennessee Valley Authority	OS	APCO 52	N/A	N/A	N/A
7	Carolina Power & Light	OS	APCO 24	N/A	N/A	N/A
8	Duke Power Co.	OS	APCO 18	N/A	N/A	N/A
9	Virginia Electric & Power	OS	APCO 16	N/A	N/A	N/A
10	PECO Energy	OS	(3)	N/A	N/A	N/A
11	Commonwealth Edison Co.	OS	IMPCO 20	N/A	N/A	N/A
12	Northern Indiana Pub Serv Co.	OS	IMPCO 22	N/A	N/A	N/A
13	Illinois Power Co.	OS	IMPCO 23	N/A	N/A	N/A
14	Indianapolis Power & Light	OS	IMPCO 21	N/A	N/A	N/A

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,559,653			$38,857,811	$29,528,360		$68,386,171	1
						0	2
						0	3
271				3,473		3,473	4
							5
146,411				2,707,647		2,707,647	6
5,026				119,426		119,426	7
11,935				360,919		360,919	8
27,315				907,741		907,741	9
25,294				700,518		700,518	10
7,531				148,706		148,706	11
575				18,842		18,842	12
222				6,305		6,305	13
3,733				72,893		72,893	14

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

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

PURCHASED POWER (Account 555) (Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ohio Edison	OS	OPCO 25	N/A	N/A	N/A
2	Allegheny Power System	OS	(3)	N/A	N/A	N/A
3	Toledo Edison Co.	OS	OPCO 35	N/A	N/A	N/A
4	Cleveland Elec Illuminating Co.	OS	OPCO 31	N/A	N/A	N/A
5	Dayton Power & Light Co.	OS	OPCO 36	N/A	N/A	N/A
6	Duquesne	OS	OPCO 33	N/A	N/A	N/A
7	Kentucky Utilities	OS	OPCO 22	N/A	N/A	N/A
8	Cincinnati Gas & Electric Co.	OS	OPCO 21	N/A	N/A	N/A
9	Central Illinois Public Serv	OS	IMPCO 67	N/A	N/A	N/A
10	Consumers Power Co.	OS	IMPCO 68	N/A	N/A	N/A
11	Louisville Gas & Electric	OS	IMPCO 70	N/A	N/A	N/A
12	IMPA	OS	(3)	N/A	N/A	N/A
13	Wisconsin Power & Light	OS	(3)	N/A	N/A	N/A
14	Cinergy Service Inc.	OS	(3)	N/A	N/A	N/A

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

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.

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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.

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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,288				$38,503		$38,503	1
1,869				72,200		72,200	2
255				8,806		8,806	3
241				11,442		11,442	4
2,209				67,739		67,739	5
624				16,886		16,886	6
905				20,520		20,520	7
5,915				150,513		150,513	8
429				15,549		15,549	9
14,685				583,670		583,670	10
5,637				132,773		132,773	11
88				5,184		5,184	12
11				853		853	13
19,086				523,386		523,386	14

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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) 12/31/97	Year of Report Dec. 31, 1997

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected 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 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 seller can unilaterally get out of the contract.

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

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

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

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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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP System Power Pool (4)	OS	APCO 20	N/A	N/A	N/A
2	AES Power, Inc.	OS	(3)	N/A	N/A	N/A
3	Louis Dreyfus Electric Power	OS	(3)	N/A	N/A	N/A
4	Electric Clearinghouse Inc.	OS	(3)	N/A	N/A	N/A
5	Enron Power Marketing Inc.	OS	(3)	N/A	N/A	N/A
6	Noram Energy Services	OS	(3)	N/A	N/A	N/A
7	Rainbow Energy Marketing	OS	(3)	N/A	N/A	N/A
8	LGE Power Marketing Inc.	OS	(3)	N/A	N/A	N/A
9	Citizens Lehman Power Sales	OS	(3)	N/A	N/A	N/A
10	CNG Energy Services	OS	(3)	N/A	N/A	N/A
11	Delmarva Power & Light	OS	(3)	N/A	N/A	N/A
12	General Public Utilities	OS	(3)	N/A	N/A	N/A
13	Pennsylvania Power & Light	OS	(3)	N/A	N/A	N/A
14	Public Service Electric & Gas	OS	(3)	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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

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.

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5. 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) 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 column (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 (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,473,607				$21,051,155		$21,051,155	1
10,646				247,927		247,927	2
13,134				343,346		343,346	3
42,911				1,122,889		1,122,889	4
116,675				2,962,061		2,962,061	5
6,266				151,802		151,802	6
132				953		953	7
17,332				432,661		432,661	8
55,514				1,250,048		1,250,048	9
8,173				201,675		201,675	10
7,975				132,363		132,363	11
484				12,610		12,610	12
13,030				340,625		340,625	13
14,840				383,470		383,470	14

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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) 12/31/97	Dec. 31, 1997

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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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1	Penn/New Jersey/Maryland Pool	OS	(3)	N/A	N/A	N/A
2	Stand Energy Inc.	OS	(3)	N/A	N/A	N/A
3	Engelhard Power Marketing Inc.	OS	(3)	N/A	N/A	N/A
4	Vitol Gas & Electric	OS	(3)	N/A	N/A	N/A
5	Wisconsin Electric Power Co.	OS	(3)	N/A	N/A	N/A
6	Sonat Power Marketing	OS	(3)	N/A	N/A	N/A
7	Aquila	OS	(3)	N/A	N/A	N/A
8	Koch	OS	(3)	N/A	N/A	N/A
9	Morgan Stanley	OS	(3)	N/A	N/A	N/A
10	Phibro	OS	(3)	N/A	N/A	N/A
11	Michigan Public Power Agency	OS	(3)	N/A	N/A	N/A
12	Midcon Power Services	OS	(3)	N/A	N/A	N/A
13	Southern Energy Trading & Marketing	OS	(3)	N/A	N/A	N/A
14	Dupont Power Marketing	OS	(3)	N/A	N/A	N/A

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PURCHASED POWER (Account 555) (Continued)
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Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,796				$58,148		$58,148	1
238				5,390		5,390	2
1,721				49,111		49,111	3
15,600				436,173		436,173	4
20				1,206		1,206	5
4,652				119,957		119,957	6
23,027				602,270		602,270	7
14,871				345,802		345,802	8
1,620				32,819		32,819	9
2,796				69,064		69,064	10
16				673		673	11
8,248				187,291		187,291	12
55,892				1,384,182		1,384,182	13
17,906				439,367		439,367	14

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PURCHASED POWER (Account 555)
(Including power exchanges)

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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.

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

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 (d)	Actual Demand(MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Elpaso Energy Marketing Co.	OS	(3)	N/A	N/A	N/A
2	Valero	OS	(3)	N/A	N/A	N/A
3	Entergy	OS	(3)	N/A	N/A	N/A
4	Federal Energy Sales Inc.	OS	(3)	N/A	N/A	N/A
5	Delhigh Energy Services	OS	(3)	N/A	N/A	N/A
6	Pan Energy Power Services Inc.	OS	(3)	N/A	N/A	N/A
7	AIG Trading Corp.	OS	(3)	N/A	N/A	N/A
8	Williams Energy Services	OS	(3)	N/A	N/A	N/A
9	AYP Energy Inc.	OS	(3)	N/A	N/A	N/A
10	Coral Power	OS	(3)	N/A	N/A	N/A
11	Pacificorp Power Marketing	OS	(3)	N/A	N/A	N/A
12	Power Company of America	OS	(3)	N/A	N/A	N/A
13	Plum Street Energy Marketing	OS	(3)	N/A	N/A	N/A
14	South Carolina Electric & Gas	OS	(3)	N/A	N/A	N/A

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
12,020				$271,228		$271,228	1
2,474				55,970		55,970	2
20,897				574,069		574,069	3
22				625		625	4
2,193				135,648		135,648	5
1,286				41,827		41,827	6
31,999				823,106		823,106	7
17,978				501,370		501,370	8
8,633				216,805		216,805	9
6,336				160,482		160,482	10
25,391				643,875		643,875	11
17,034				386,840		386,840	12
1,344				30,889		30,889	13
3,888				90,097		90,097	14

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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) 12/31/97	Year of Report Dec. 31, 1997

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected 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 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 seller can unilaterally get out of the contract.

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

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

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

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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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	WPS Energy Services	OS	(3)	N/A	N/A	N/A
2	Equitable Power Services	OS	(3)	N/A	N/A	N/A
3	NESI Power Marketing	OS	(3)	N/A	N/A	N/A
4	Conagra Energy Services	OS	(3)	N/A	N/A	N/A
5	Southern Company Services	OS	(3)	N/A	N/A	N/A
6	U.S. Gen Power Services	OS	(3)	N/A	N/A	N/A
7	American Energy Solutions	OS	(3)	N/A	N/A	N/A
8	Enerz Corp	OS	(3)	N/A	N/A	N/A
9	CMS Marketing	OS	(3)	N/A	N/A	N/A
10	Detroit Edison	OS	(3)	N/A	N/A	N/A
11	City of Bryan	OS	(3)	N/A	N/A	N/A
12	Constellation Power Source	OS	(3)	N/A	N/A	N/A
13	Engage Energy	OS	(3)	N/A	N/A	N/A
14	Tractebel Energy Marketing	OS	(3)	N/A	N/A	N/A

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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) 12/31/97	Year of Report Dec. 31, 1997

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

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
602				$10,142		$10,142	1
2,043				47,378		47,378	2
6,875				160,853		160,853	3
5,324				130,516		130,516	4
4,836				149,050		149,050	5
5,964				158,317		158,317	6
1,128				48,506		48,506	7
3,121				76,259		76,259	8
3,438				85,761		85,761	9
1,229				58,668		58,668	10
12				1,212		1,212	11
6,922				154,016		154,016	12
1,223				29,900		29,900	13
5,915				148,854		148,854	14

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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 seller can unilaterally get out of the contract.

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW): Average Monthly NCP Demand (e)	Actual Demand(MW): Average Monthly CP Demand (f)
1	National Power Energy Inc.	OS	(3)	N/A	N/A	N/A
2	Eastern Group	OS	(3)	N/A	N/A	N/A
3	AMOCO Energy Trading Corp.	OS	(3)	N/A	N/A	N/A
4	Market Responsive Energy Inc.	OS	(3)	N/A	N/A	N/A
5	North American Energy	OS	(3)	N/A	N/A	N/A
6	N.Y. State Energy & Gas Corp.	OS	(3)	N/A	N/A	N/A
7	Atlantic Electric	OS	(3)	N/A	N/A	N/A
8	Central Illinois Light	OS	(3)	N/A	N/A	N/A
9	Entergy Power Inc.	OS	(3)	N/A	N/A	N/A
10	QST Energy Trading Inc.	OS	(3)	N/A	N/A	N/A
11	Proliance Energy	OS	(3)	N/A	N/A	N/A
12	Sigeco	OS	(3)	N/A	N/A	N/A
13	Pacific Gas & Electric Co.	OS	(3)	N/A	N/A	N/A
14	AECI	OS	(3)	N/A	N/A	N/A

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(Including power exchanges)

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.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 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) 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 column (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 (1) 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.

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Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
10,110				$251,941		$251,941	1
9,733				231,312		231,312	2
7,045				165,187		165,187	3
7,319				181,779		181,779	4
6,506				158,051		158,051	5
5,537				144,430		144,430	6
1,774				52,596		52,596	7
215				4,813		4,813	8
9				191		191	9
108				2,006		2,006	10
269				5,918		5,918	11
968				26,629		26,629	12
2,366				63,649		63,649	13
161				2,985		2,985	14

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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) 12/31/97	Year of Report Dec. 31, 1997

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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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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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	East Kentucky Power Coop	OS	KYPCO 14	N/A	N/A	N/A
2						
3	Loop Regulation Energy			N/A	N/A	N/A
4	Misc. Adjustments to MWH (5)					
5						
6	TOTAL					
7						
8						
9						
10						
11						
12						
13						
14						

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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) 12/31/97	Year of Report Dec. 31, 1997

PURCHASED POWER (Account 555) (Continued)
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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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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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 (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

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

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
459				$10,673		$10,673	1
						0	2
582				(1,788)		(1,788)	3
47,495						0	4
							5
5,072,113	0	0	38,857,811	75,080,527	0	113,938,338	6
							7
							8
							9
							10
							11
							12
							13
							14

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< Page 326 Line 1 Column B >

KENTUCKY POWER COMPANY

NOTES:

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

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

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

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

(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.

(5) OVEC surplus and supplemental losses (net)

Loop regulation energy difference	105
Non-displacement payback losses	0
Purchased Power transfer losses	11,476
Unit power losses (net)	8,097
AEP System Power Pool losses	27,817
TOTAL	47,495

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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) 12/31/97	Year of Report Dec. 31, 1997

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 or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	*			
2	Virginia Electric & Power Co.	Ohio Power Company (Assoc.)	Virginia Electric Power Co.	LF
3	Wabash Valley Power Assn.	Various	Various	LF
4	Blue Ridge Agency	PSI Energy	Blue Ridge Agency	LF
5	AES Power, Inc.	Various	AEP System	OS
6	AIG Trading Corp.	Various	Various	OS
7	Allegheny Power Systems	Various	Various	OS
8	AMP-Ohio, Inc.	Various	Various	OS
9	Aquila, Inc.	Various	Various	OS
10	AYP Energy, Inc.	Various	Various	OS
11	Commonwealth Edison	Various	Various	OS
12	Cleveland Electric Illuminating	Various	Various	OS
13	Cinergy	Various	Various	OS
14	Citizens Lehman	Various	Various	OS
15	Constellation Power Source	Various	Various	OS
16	CMS Marketing Serv & Trading	Various	Various	OS
17	Coral Power, LLC	Various	Various	OS

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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) 12/31/97	Year of Report Dec. 31, 1997

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

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

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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatthours Received (i)	TRANSFER OF ENERGY Megawatthours Delivered (j)	Line No.
						1
APCo 16	Ohio Power Company	Virginia Elec Pwr		158,091	154,897	2
IMPCo 76	Various	Various		58,130	57,439	3
See Footnotes	Various	Blue Ridge		24,156	23,286	4
See Footnotes	Various	Various		1,051	1,054	5
See Footnotes	Various	Various		209	209	6
OPCo 73	Various	Various		117	117	7
OPCo 74	Various	Various		81,742	80,470	8
See Footnotes	Various	Various		5,366	5,366	9
See Footnotes	Various	Various		4,082	4,040	10
IMPCo 73	Various	Various		98,530	97,257	11
OPCo 31	Various	Various		155	314	12
OPCo 21	Various	Various		47,981	47,961	13
See Footnotes	Various	Various		170	170	14
See Footnotes	Various	Various		431	431	15
See Footnotes	Various	Various		348	348	16
See Footnotes	Various	Various		874	874	17

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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 Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Carolina Power & Light Company	Various	Various	OS
2	Cleveland Public Power	Various	Various	OS
3	Delhi Energy Services	Various	Various	OS
4	Dayton Power & Light	Various	Various	OS
5	Duquesne Light Company	Various	Various	OS
6	Detroit Edison	Various	Various	OS
7	Duke Power Co.	Various	Various	OS
8	Electric Clearinghouse, Inc.	Various	Various	OS
9	East Kentucky Power Coop	Various	Various	OS
10	Engage Energy	Various	Various	OS
11	Enron Power Marketing, Inc.	Various	Various	OS
12	Federal Energy Sales	Various	Various	OS
13	City Of Bryan	Various	Various	OS
14	City Of Hamilton	Various	Various	OS
15	Illinova Power Marketing	Various	Various	OS
16	Indiana Municipal Power Agency	Various	Various	OS
17	Koch Power Services	Various	Various	OS

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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) 12/31/97	Year of Report Dec. 31, 1997

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.
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Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Louisville Gas & Electric	Various	Various	OS
2	LG&E Power Marketing, Inc.	Various	Various	OS
3	Louis Dreyfus Electric Power, Inc.	Various	Various	OS
4	Midcon Power Services Corp.	Various	Various	OS
5	MECS	Various	Various	OS
6	Morgan Stanley & Co., Inc.	Various	Various	OS
7	NESI	Various	Various	OS
8	Northern Indiana Public Service Co.	Various	Various	OS
9	Noram Energy Services	Various	Various	OS
10	Ohio Edison	Various	Various	OS
11	PAN Energy Power Services	Various	Various	OS
12	Power Company Of America	Various	Various	OS
13	Philadelphia Electric Company	Various	Various	OS
14	Rainbow Energy Marketing Corp.	Various	Various	OS
15	Public Service Electric & Gas	Various	Various	OS
16	Pennsylvania Power & Light	Various	Various	OS
17	Sonat Power Marketing	Various	Various	OS

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
	$19,028	$2,455	$21,483	1
	132,123	10,362	142,485	2
	15,096	2,282	17,378	3
	13,954	2,508	16,462	4
	52	19	71	5
	5,799	572	6,371	6
	2,761	315	3,076	
	19,351	1,898	21,249	8
	31,338	3,914	35,252	9
	121	13	134	10
	108,010	14,257	122,267	11
	31,556	5,678	37,234	12
	830	212	1,042	13
	1,029	211	1,240	14
	609,077	49,369	658,446	15
	116,854	19,966	136,820	16
	71,758	8,626	80,384	17

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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) 12/31/97	Year of Report Dec. 31, 1997

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.
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4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:

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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 Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Stand Power Marketing	Various	Various	OS
2	Pacificorp Power Marketing	Various	Various	OS
3	Southern Company Services	Various	Various	OS
4	Southern Energy Trading & Marketing	Various	Various	OS
5	Toledo Edison	Various	Various	OS
6	Virginia Electric Power	Various	Various	OS
7	Vitol Gas & Electric, LLC	Various	Various	OS
8	Western Power Services	Various	Various	OS
9	Wisconsin Power & Light	Various	Various	OS
10	Wisconsin Electric Power	Various	Various	OS
11	Cities Of Bedford & Danville	Various	Various	OS
12	North Carolina Electric Membership Corp.	AEP System	See Footnotes	LF
13				
14	Losses Associated with Wheeling Power			
15				
16	TOTAL			
17				

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

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

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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				Megatthours Received (i)	Megatthours Delivered (j)	
See Footnotes	Various	Various		14,724	14,723	1
See Footnotes	Various	Various		369	369	2
See Footnotes	Various	Various		44	44	3
See Footnotes	Various	Various		7,545	7,545	4
OPCo 35	Various	Various		815	657	5
See Footnotes	Various	Various		16,661	16,590	6
APCo 16	Various	Various		6,969	6,966	
See Footnotes	Various	Various		311	311	
See Footnotes	Various	Various		10	10	9
See Footnotes	Various	Various		7	7	10
See Footnotes	Various	Various		12,373	11,929	11
See Footnotes	Various	Various				12
						13
				(8,822)		14
						15
				1,295,226	1,295,226	16
						17

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megatthours Received (i)	TRANSFER OF ENERGY Megatthours Delivered (j)	Line No.
APCo 24	Various	Various		5,098	5,022	1
See Footnotes	Various	Various		37,807	37,644	2
See Footnotes	Various	Various		4,147	4,138	3
OPCo 36	Various	Various		5,466	5,466	4
See Footnotes	Various	Various		40	40	5
See Footnotes	Various	Various		1,242	1,242	6
APCo 18	Various	Various		401	401	7
See Footnotes	Various	Various		4,497	4,497	8
KPCo 14	Various	Various		6,511	7,118	9
See Footnotes	Various	Various		27	27	10
See Footnotes	Various	Various		28,108	28,158	11
See Footnotes	Various	Various		8,790	8,657	12
See Footnotes	Various	Various		108	108	13
See Footnotes	Various	Various		401	401	14
See Footnotes	Various	Various		110,785	110,066	15
See Footnotes	Various	Various		41,622	41,616	16
See Footnotes	Various	Various		15,630	15,598	17

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
				1
	754,398	51,654	806,052	2
	313,889	29,350	343,239	3
	67,943	10,811	78,754	4
	144,184	15,930	160,114	5
	748	96	844	6
	408	54	462	7
	225,228	32,587	257,815	8
	21,722	3,383	25,105	9
	11,806	1,964	13,770	10
	507,758	44,639	552,397	11
	665	71	736	12
	274,044	20,499	294,543	13
	785	78	863	14
	2,373	299	2,672	15
	2,101	160	2,261	16
	5,260	556	5,816	17

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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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatthours Received (i)	Megawatthours Delivered (j)	Line No.
See Footnotes	Various	Various		27	27	1
See Footnotes	Various	Various		1,414	1,414	2
See Footnotes	Various	Various		2,765	2,771	3
See Footnotes	Various	Various		309	308	4
See Footnotes	Various	Various		2,640	2,640	5
See Footnotes	Various	Various		10,136	9,774	6
See Footnotes	Various	Various		4,707	4,706	7
IMPCo 22	Various	Various		464	464	8
See Footnotes	Various	Various		510	510	9
OPCo 25	Various	Various		221	221	10
See Footnotes	Various	Various		1,968	1,972	11
See Footnotes	Various	Various		2,751	2,749	12
See Footnotes	Various	Various		452,314	452,208	13
See Footnotes	Various	Various		1,845	1,845	14
See Footnotes	Various	Various		54	54	15
See Footnotes	Various	Various		61	61	16
See Footnotes	Various	Various		9,921	9,919	17

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
	$205	$37	$242	1
	5,171	704	5,875	2
	8,934	1,342	10,276	3
	845	150	995	4
	8,523	1,176	9,699	5
	6,910	8,767	15,677	6
	19,275	2,595	21,870	
	3,048	280	3,328	
	1,491	241	1,732	9
	1,633	124	1,757	10
	8,224	997	9,221	11
	11,820	2,925	14,745	12
	1,443,487	129,664	1,573,151	13
	8,350	868	9,218	14
	296	25	321	15
	392	37	429	16
	38,527	5,177	43,704	17

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary 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.
	$42,615	$3,666	$46,281	1
	1,660	171	1,831	2
	76	20	96	3
	33,909	5,066	38,975	4
	1,503	303	1,806	5
	60,593	10,318	70,911	6
	22,773	3,712	26,485	7
	1,334	194	1,528	8
	35	5	40	9
	24	3	27	10
	34,801	5,537	40,338	11
	123,996	21,870	145,866	12
				13
				14
				15
0	5,402,499	540,762	5,943,261	16
				17

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< Page 329 Line 4 Column e >

Page 329 Lines 4, 5, 6, 9, 10, 14-17 Column (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.

Page 329.1 Lines 2, 3, 5, 6, 8, 10-17 Column (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.

Page 329.2 Lines 1-7, 9, 11-17 Column (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.

Page 329.3 Lines 1-4, 6, 8-11 Column (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.

Page 328.3 and 329.3 Line 12 Column (c) and Column (e)

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.

Column (d) Earliest termination date - December 31, 2010.

Page 329.3 Line 14 Column (i) and (j)

Excludes North Carolina Electric Membership Corp., Line 12 inasmuch as these MWH are included in Account 447.

The Respondent, Columbus Southern Power Company, 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.

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(Next page is 332)

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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 provided transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.

3. Provide in column (a) subheadings and classify transmission service purchased from 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 (g) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") in column (g). Provide a footnote explaining the nature of the nonmonetary 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 losses 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 Megawatt-hours Received (b)	Megawatt-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 Sys Tran/Agreemen					($2,755,984)	($2,755,984)
2	East KY Coop.					177,748	177,748
3	Allegheny Power System	1,605	1,605	4,551			4,551
4	Carolina P&L	8,462	8,462		649		[illegible]
5	Cen Illinois Pwr Ser	232	232		980		[illegible]
6	Cinergy	5,862	5,862		10,162		10,162
7	Dayton P&L	20	20	146			146
8	Duke Power	55,832	55,814	50,649			50,649
9	Mich Elec Coor System	242	242		1,466		1,466
10	Norther Indiana Pub Ser	645	645		1,855		1,855
11	Ohio Edison	107	107	311			311
12	Ohio Valley Electric Co	194	194		313		313
13	Tennessee Valley Author	1,210	1,210	2,848			2,848
14	Virginia Power	50,916	50,916	89,761			89,761
15	Line Losses	(18)					
16	TOTAL	125,309	125,309	148,266	15,425	(2,578,236)	(2,414,545)

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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) 12/31/97	Year of Report Dec. 31, 1997

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 provided transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.

3. Provide in column (a) subheadings and classify transmission service purchased from 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 (g) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") in column (g). Provide a footnote explaining the nature of the nonmonetary 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 losses 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 Megawatt-hours Received (b)	Megawatt-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 Sys Tran/Agreemen					($2,755,984)	($2,755,984)
2	East KY Coop.					177,748	177,748
3	Allegheny Power System	1,605	1,605	4,551			4,551
4	Carolina P&L	8,462	8,462		649		[illegible]
5	Cen Illinois Pwr Ser	232	232		980		
6	Cinergy	5,862	5,862		10,162		10,162
7	Dayton P&L	20	20	146			146
8	Duke Power	55,832	55,814	50,649			50,649
9	Mich Elec Coor System	242	242		1,466		1,466
10	Norther Indiana Pub Ser	645	645		1,855		1,855
11	Ohio Edison	107	107	311			311
12	Ohio Valley Electric Co	194	194		313		313
13	Tennessee Valley Author	1,210	1,210	2,848			2,848
14	Virginia Power	50,916	50,916	89,761			89,761
15	Line Losses	(18)					
16	TOTAL	125,309	125,309	148,266	15,425	(2,578,236)	(2,414,545)

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KENTUCKY POWER COMPANY

NOTE:
1) The respondent, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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.

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) 12/31/97	Dec. 31, 1997

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)(ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$887,[illegible]
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	27,114
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	66,132
5	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less that $5,000 by classes if the number of items so grouped is shown)	
6	Non Energy T & D Business	$88,143
7	Interest Cost on AEP Borrowed Capital	23,429
8	Load Research - Time of Day	22,392
9	AEP Service Corp. Federal Income Taxes & Credits	(6,054)
10	Management Development Training - General	7,055
11	Management Development Activities - General	32,746
12	ABMS Enhancements	197,870
13	Financial Integration Projects	107,027
14	AEP Corporate Services	695,840
15	Power Industry Computer Applications Conference	11,360
16	Other Items (107) Under $5,000	109,878
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46	TOTAL	$2,270,774

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition 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 B 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 section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average 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		$625		$625
2	Steam Product Plant	9,162,612			9,162,612
3	Nuclear Production Plant				0
4	Hydraulic Production Plant--Conventional				0
5	Hydraulic Production Plant--Pumped Storage				0
6	Other Production Plant				0
7	Transmission Plant	4,545,098			4,545,098
8	Distribution Plant	11,612,502			11,612,502
9	General Plant	927,386	186,937		1,114,323
10	Common Plant--Electric				0
11	TOTAL	$26,247,598	$187,562		$26,435,160

B. Basis for Amortization Charges

The $187,562 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	* 246,113					
13	Transmission	301,041					
14	Distribution	349,692					
15	General	36,839					
16							
17							
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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 Production 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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KENTUCKY POWER COMPANY	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/97	Dec. 31, 1997

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 accounts. 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 2	425 - MISCELLANEOUS AMORTIZATION	0
3	TOTAL-425	0
4		
5	426 - OTHER INCOME DEDUCTIONS	
6		
7	426.1 - DONATIONS	
8		
9	EDUCATIONAL	
10	Miscellaneous Items Under 5% of Account Total	27,173
11		
12	MEDICAL	
13	Pikeville Osteopathic	20,0[illegible]
14	Miscellaneous Items Under 5% of Account Total	2,[illegible]
15		
16	COMMUNITY	
17	Paramount Arts Center	10,000
18	Tri-State Fair & Regatta	10,000
19	Miscellaneous Items Under 5% of Account Total	110,453
20		
21	OTHER DONATIONS	
22	Miscellaneous Items Under 5% of Account Total	29,533
23		
24	TOTAL-426.1	209,259
25		
26	426.3 - PENALTIES	0
27		
28	TOTAL-426.3	0
29		
30	426.4 - EXPENDITURES FOR CERTAIN CIVIC, POLITICAL,	
31	& RELATED ACTIVITIES	
32		
33	Labor	75,361
34	Transportation	4,858
35	Employee Expenses	60,333
36	Lobbying Expenses of Parent Co. Employees	82,429
37	Miscellaneous Expenses	6,696
38		
39	TOTAL-426.4	229,6[illegible]
40 41		

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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 accounts. 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 INCOME DEDUCTIONS	
2		
3	Various Club Dues & Memberships Each Under 5%	
4	of Account Total	25,501
5	Write Down of ETS Furnace to Est. Sales Price	9,013
6	Customer Financing Program	587,880
7	Options	20,154
8	HMS-Partners LTD of OHIO	118,305
9	Miscellaneous Items Under 5% of Account Total	106
10		
11	TOTAL-426.5	760,959
12		
13	TOTAL 426	1,199,895
14		
15	431 - OTHER INTEREST EXPENSE	
16		
17	Short Term Notes - Various	127,629
18	Commercial Paper - Various	2,837,101
19	Lines of Credit Fees	69,000
20	Customer Deposits - 6%	201,671
21	Miscellaneous	74
22		
23	TOTAL 431	3,235,475
24		
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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) 12/31/97	Year of Report Dec. 31, 1997

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 formal 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 Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of year (e)
1	FERC Assesment 96-97		$152,998	$152,998	
2					
3	FERC Assesment 97-98		47,499	47,499	
4					
5	FERC Assesment-Bookouts 97-98		20,134	20,134	
6					
7	Kentucky PSC Case No.96-520 Fuel Adjustment			0	
8	Clause Review		27,168	27,168	
9					
10	Miscellaneous		23,336	23,336	
11					
12					
13					
14					
15					
16					
17					
18					
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44					
45					
46	TOTAL	0	$271,135	$271,135	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	12/31/97	Dec. 31, 1997

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.

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EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3, End of Year (l)	Line No.
Electric	928	$152,998					1
							2
Electric	928	47,499					3
							4
Electric	928	20,134					5
							6
							7
Electric	928	27,168					8
							9
Electric	928	23,336					10
							11
							12
							13
							14
							15
							16
							17
							18
							19
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							41
							42
							43
							44
							45
		$271,135	0		0	0	46

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	12/31/97	Dec. 31, 1997

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (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	
4	A(1)B GENERATION: FOSSIL-FUEL STEAM	3 ITEMS UNDER $5,000
6	A(1)D GENERATION: NUCLEAR	ADVANCED PRESSURIZED WATER REACTOR DESIGN
8	A(3)A TRANSMISSION: OVERHEAD	4 ITEMS UNDER $5,000
10	A(4) DISTRIBUTION:	3 ITEMS UNDER $5,000
12	A(5) ENVIRONMENT: (OTHER THAN EQUIPMENT)	4 ITEMS UNDER $5,000
14	A(6) OTHER:	8 ITEMS UNDER $5,000
16	A(7) TOTAL COST INCURRED INTERNALLY	
18	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
19	DEMONSTRATION PERFORMED EXTERNALLY	
21	B(1) RESEARCH SUPPORT TO THE ERC OR THE EPRI:	1 ITEM UNDER $5,000
23	B(5) TOTAL COSTS INCURRED EXTERNALLY	
25	GRAND TOTAL	

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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 accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
2,753		506	2,753		4
					5
12,921		930	12,921		6
					7
1,486		588/539	1,486		8
					9
2,112		588/506	2,112		10
					11
5,804		506/930	5,804		12
					13
12,906		588/930	12,906		14
					15
37,982			37,982		16
					17
					18
					19
					20
	2,251	506	2,251		21
					22
	2,251		2,251		23
					24
37,982	2,251		40,233		25
					26
					27
					28
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KENTUCKY POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/97	Dec. 31, 1997

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	$4,805,749		
4	Transmission	511,002		
5	Distribution	3,578,412		
6	Customer Accounts	3,480,851		
7	Customer Service and Informational	1,295,472		
8	Sales	105,399		
9	Administrative and General	2,048,649		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	$15,825,534		
11	Maintenance			
12	Production	2,990,779		
13	Transmission	515,395		
14	Distribution	3,064,942		
15	Administrative and General	567,140		
16	TOTAL Maint. (Total of lines 12 thru 15)	$7,138,256		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	$7,796,528		
19	Transmission (Enter Total of lines 4 and 13)	$1,026,397		
20	Distribution (Enter Total of lines 5 and 14)	$6,643,354		
21	Customer Accounts (Transcribe from line 6)	3,480,851		
22	Customer Service and Informational(Transcribe from line 7)	1,295,472		
23	Sales (Transcribe from line 8)	105,399		
24	Administrative and General (Enter Total of lines 9 and 15)	$2,615,789		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	$22,963,790	$1,765,599	$24,729,389
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)
	Gas			
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 of lines 29 and 41)			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	$22,963,790	$1,765,599	$24,729,389
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	7,938,746	1,269,330	9,208,076
66	Gas Plant			0
67	Other			
68	TOTAL Construction (Total of lines 65 thru 67)	$7,938,746	$1,269,330	$9,208,076
69	Plant Removal (By Utility Departments)			
70	Electric Plant	630,870	156,881	787,751
71	Gas Plant			
72	Other			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	$630,870	$156,881	$787,751
74	Other Accounts (Specify):			
75	Fuel Stock Expenses-Undistributed	695,360	(695,360)	0
76	Stores Expense-Undistributed-T&D Expense	1,218,739	(1,157,802)	60,937
77	Stores Expense-Undistributed-Power Plant	0		0
78	Transportation Expenses-Maintenance	429,791	(409,591)	20,200
79	Transportation Expenses-Accidents	975	(929)	46
80	Transportation Expenses-O&M-General & OH	173,992	(165,814)	8,178
81	Building Service-Clearing	116,648	(116,648)	0
82	MDD-Other Work In Progress	440,435	(440,435)	0
83	Expenditures to CNIC, Political, & R/A	73,252		73,252
84				0
85	Non-Productive Payroll	216,489	(205,231)	11,258
86				0
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	$3,365,681	($3,191,810)	$173,871
96	TOTAL SALARIES AND WAGES	$34,899,087	0	$34,899,087

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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)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,514,540
3	Steam	7,639,652	23	Requirements Sales for Resale (See instruction 4, page 311.)	78,753
4	Nuclear		24	Non-Requirements Sales For Resale (See instruction 4, page 311.)	5,815,179
5	Hydro--Conventional		25	Energy Furnished Without Charge	
6	Hydro--Pumped Storage		26	Energy Used by the Company (Electric Department Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	303,293
8	(Less) Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Thru 27) (MUST EQUAL LINE 20)	12,711,765
9	Net Generation (Enter Total of lines 3 thru 8)	7,639,652			
10	Purchases	5,072,113			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	1,295,226			
17	Delivered	1,295,226			
18	Net Transmission for Other (Line 16 minus Line 17)	0			
19	Transmission By Other Losses				
20	TOTAL (Enter Total of Lines 9, 10, 14, 18 and 19)	12,711,765			

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-Requirements Sales For Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
29	January	1,108,838	403,159	1,417	17	0900
30	February	946,510	389,575	1,105	17	0900
31	March	1,042,347	479,950	1,041	7	0900
32	April	975,298	424,726	1,088	10	0800
33	May	946,308	431,822	932	16	0800
34	June	863,087	349,186	1,074	24	1500
35	July	995,171	411,980	1,164	28	1400
36	August	1,098,468	542,545	1,084	12	1400
37	September	1,103,420	606,928	1,116	2	1500
38	October	1,285,703	732,220	1,075	23	0800
39	November	1,168,638	552,885	1,237	18	1000
40	December	1,177,977	490,203	1,266	15	0900
41	TOTAL	12,711,765	5,815,179			

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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 on 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 of the gas and the quantity of fuel burned converted to Mcf.
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 (Steam, Internal Combustion, Gas Turbine or Nuclear)	STEAM	
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	CONVENTIONAL	
3	Year Originally Constructed	1963	
4	Year Last Unit was Installed	1969	
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	1,096.80	
6	Net Peak Demand on Plant -- MW (60 minutes)	1,122	
7	Plant Hours Connected to Load	8,669	
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water	1,060	
10	When Limited by Condenser Water	0	
11	Average Number of Employees	177	
12	Net Generation,Exclusive of Plant Use --KWh	7,639,652,000	
13	Cost of Plant: Land and Land Rights	1,076,545	
14	Structures and Improvements	26,682,170	
15	Equipment Costs	219,425,448	
16	Total Cost	$247,184,163	
17	Cost per KW of Installed Capacity (line 5)	225.3684	
18	Production Expenses: Oper. Supv. & Engr.	2,811,684	
19	Fuel	78,355,272	
20	Coolants and Water (Nuclear Plants Only)		
21	Steam Expenses	2,580,010	
22	Steam From Other Sources	0	
23	Steam Transferred (Cr.)	0	
24	Electric Expenses	304,160	
25	Misc. Steam (or Nuclear) Power Expenses	2,166,771	
26	Rents	7,491	
27	Allowances	0	
28	Maintenance Supervision and Engineering	2,018,601	
29	Maintenance of Structures	1,109,889	
30	Maintenance of Boiler (Or Reactor) Plant	5,350,664	
31	Maintenance of Electric Plant	925,038	
32	Maintenance Misc. Steam (or Nuclear) Plant	612,154	
33	Total Production Expenses	$96,241,734	
34	Expenses per Net KWh	$0.0125	

Line No.	Item (a)	(b)			(c)		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	COAL	* OIL				
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	TONS	BARRELS				
37	Quantity (Units) of Fuel Burned	2,896,162	30,112				
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	12,123	139,279				
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$27.064	$25.272				
40	Average Cost of Fuel per Unit Burned	$26.767	$27.683				
41	Avg. Cost of Fuel Burned per Million Btu	$1.104	$4.732				
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.010					
43	Average Btu per KWh Net Generation	9,255.000					

< Page 402 Line 35 Column B >

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

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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) 12/31/97	Year of Report Dec. 31, 1997

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	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		
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	WP	45.62		
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		
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			

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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) 12/31/97	Year of Report Dec. 31, 1997

TRANSMISSION LINE STATISTICS (Continued)

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

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

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

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

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
954 MCMA	$258	$10,281	$10,539					1
954 MCMA	554,508	5,276,357	5,830,865					2
								3
954 MCMA	$2,668,325	$14,691,137	$17,359,462					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	$1,736,562	$1,934,184					9
								10
556.5 VAR	$492,653	$1,220,850	$1,713,503					11
								12
1033.5 VAR	$8,672	$63,923	$72,595					13
397.5 MA	$4,478	$168,524	$173,002					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	$2,477,341	$2,996,819					22
								23
								24
795 MCMA	$16,110	$297,567	$313,677					25
			0					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		$1,474,091	$1,474,091					33
10335 VAR	$459,548	$3,873,360	$4,332,908					34
10335 VAR	$2,783	$251,650	$254,433					35
								36

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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) 12/31/97	Year Dec.

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 typ ing structure, indicate the mileage of each type by the use of brackets and extra lines. Minor po transmission line of a different type of construct be distinguished from the remainder of the line.

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structure of Another Line (g)
1	0126 INEZ	MARTIKI	138.00	138.00	WP	0.33	
2	0106 DORTON	FLEMING	138.00	138.00	WP	7.64	
3	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60	
4	0112 MASSEY	LOVELY	69.00	138.00	WP	4.34	
5	0114 LOVELY	MCCLURE	69.00	138.00	WP	6.96	
6	0123 ENGLE TAP		69.00	138.00	WP	4.60	
7	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01	
8	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00			
9	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22	
10	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00	
11							
12							
13							
14	9069 69KV LINES AND BELOW		69.00	69.00		589.56	
15							
16							
17	765KV EXPENSES						
18							
19	345KV EXPENSES						
20							
21	161KV EXPENSES						
22							
23	138KV EXPENSES						
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36					TOTAL	1,174.46	4(

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TRANSMISSION LINE STATISTICS (Continued)

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

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

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

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

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
10335 VAR	$2,269	$56,174	$58,443					1
795 MCMA	217,206	1,174,346	1,391,552					2
397 MCMA	$118,238	$1,318,842	$1,437,080					3
795 MCMA	$40,398	$292,027	$332,425					4
795 MCMA	$121,009	$451,593	$572,602					5
10335 VAR	$120,301	$1,185,444	$1,305,745					6
10335 VAR		$97,436	$97,436					7
	$51,485		$51,485					8
795 ACSR		$225,286	$225,286					9
1351 KCM	0	$1,181,718	$1,181,718					10
								11
								12
								13
	$2,396,259	$27,667,877	$30,064,136	$63,572	$582,519	0	$646,091	14
								15
								16
				$27,799	$254,731		$282,530	17
								18
				$901	$8,260		$9,161	19
								20
				$4,997	$45,787		$50,784	21
								22
				$29,371	$269,137		$298,508	23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	$26,773,115	$174,083,777	$200,856,892	$126,640	$1,160,434	0	$1,287,074	36

Name of Respondent KENTUCKY POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/97	Year of Report Dec. 31, 1997

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-CODS	T-U	138.00	69.00	12.00
5		T-U	138.00	34.00	
6	DORTON-DORTON	T-U	138.00	46.00	
7	DORTON-PIKEVILLE	T-U	46.00	4.20	
8	DRAFTIN-MARROWBONE	D-U	46.00	12.00	
9	ELKHORN CITY-ELKHORN CITY	T-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	34.50	
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	GARRETT-GARRETT	D-U	46.00	34.00	
21		D-U	34.00	12.00	
22	GRAYSON	D-U	69.00	12.00	
23	HADDIX-HADDIX	D-U	69.00	34.00	
24	HATFIELD-SO. WILLIAMSON	T-U	138.00	69.00	46.00
25		T-U	46.00	7.20	
26	HAZARD-LOTHAIR	T-U	138.00	69.00	12.00
27		T-U	161.00	138.00	11.00
28		T-U	138.00	34.00	
29		T-U	34.00	12.00	
30	HAZARD	T-U	69.00	12.00	
31	JENKINS-PIKEVILLE	D-U	69.00	12.00	
32	MAYKING-PIKEVILLE	D-U	69.00	13.00	
33	ASHLAND-ASHLAND	D-U	69.00	12.00	
34	BAKER-LOUISA	T-U	765.00	345.00	34.50
35	BAKER	T-U	345.00	138.00	34.50
36	BARRENSHE-FREEBURN	D-U	69.00	12.00	
37	BEAVER CREEK-CLEAR CR. JCT.	T-U	138.00	69.00	46.00
38		T-U	138.00	46.00	12.00
39		T-U	69.00	12.00	
40		T-U	138.00	8.30	

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SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4.00	1					1
20.00	1					2
25.00	1		STAT CAP	1	10	3
90.00	1		STAT CAP	1	27	4
25.00	1					5
45.00	1					6
2.00	3					7
11.00	1					8
7.00	1		STAT CAP	1	14	9
20.00	1					10
25.00	1		STAT CAP	1	11	11
20.00	1					12
20.00	1					13
20.00	1					14
12.00	1					15
130.00	1		STAT CAP	1	14	16
20.00	1					17
30.00	1					18
20.00	1					19
20.00	1					20
5.00	1					21
20.00	1					22
25.00	1					23
60.00	1					24
4.00	1					25
180.00	2		STAT CAP	2	46	26
90.00	1	1				27
30.00	1					28
6.00	2					29
4.00	1	1				30
10.00	1					31
20.00	1					32
20.00	1		STAT CAP	1	16	33
1,500.00	3	5	REACTOR	3	300	34
672.00	1					35
15.00	1					36
30.00	1		STAT CAP	8	317	37
38.00	3	1	REACTOR	6	126	38
5.00	1					39
125.00	1					40

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SUBSTATIONS

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	BECKHAM-HINDMAN	D-U	138.00	34.00	
2	BEEFHIDE-JENKINS	D-U	138.00	34.50	
3	BELHAVEN-FLATWOODS	D-U	138.00	12.00	
4	BELLEFONTE-BELLEFONTE	T-U	138.00	34.50	
5		T-U	138.00	69.00	34.00
6	BELLEFONTE-BELLEFONTE	T-U	138.00	69.00	34.00
7		T-U	138.00	12.00	
8	BETSY LAYNE-BETSY LAYNE	T-U	46.00	12.00	
9		T-U	138.00	69.00	46.00
10		T-U	138.00	34.00	
11	BIG SANDY-LOUISA	T-A	138.00	4.00	
12		T-A	22.00	4.00	
13		T-A	345.00	24.50	
14		T-A	138.00	23.00	
15		T-A	138.00	69.00	34.50
16		T-A	138.00	34.00	12.00
17		T-A	138.00	34.50	
18	BONNYMAN-BONNYMAN	T-U	69.00	34.00	
19	BUSSEYVILLE-BUSSEYVILLE	D-U	138.00	34.00	
20	CANNONSBURG-ASHLAND	D-U	69.00	34.00	
21	CEDAR CREEK-PIKEVILLE	T-U	138.00	69.00	46.00
22	CEDAR CREEK	T-U	46.00	0	
23		T-U	34.50	12.00	
24	CHADWICK-CHADWICKS CREEK	T-U	138.00	69.00	34.50
25	CLINTWOOD	D-U	69.00	12.00	
26	COALTON-COALTON	D-U	69.00	12.00	
27	HENRY CLAY-HELLIER	D-U	46.00	34.00	
28	HITCHINS-HITCHINS	D-U	69.00	12.00	
29	HOWARD COLLINS-ASHLAND	D-U	69.00	12.00	
30	INEZ-INEZ	D-U	138.00	69.00	
31	INEZ	D-U	13.33	37.00	13.80
32		D-U	138.00	37.00	
33	JACKSON-JACKSON	T-U	69.00	12.00	
34	JEFF-PIKEVILLE	D-U	69.00	13.00	
35	JOHNS CREEK-KIMPER	T-U	138.00	69.00	34.00
36	KENWOOD-PAINTSVILLE	D-U	46.00	12.00	
37	KEYSER-KEYSER	D-U	69.00	12.00	
38	LESLIE-WOOTEN	T-U	161.00	69.00	12.00
39		T-U	69.00	34.00	12.00
40	LOUISA-LOUISA	D-U	34.00	12.00	

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SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25.00	1					1
20.00	1					2
20.00	1					3
46.50	1					4
196.00	1					5
100.00	1					6
20.00	1					7
7.00	2		STAT CAP	1	10	8
30.00	1					9
25.00	1					10
38.00	2					11
80.00	4					12
950.00	1					13
300.00	2					14
90.00	1					15
8.00	1					16
20.00	1					17
25.00	1					18
25.00	1					19
25.00	1					20
90.00	1					21
111.00	1					22
3.13	1	1				23
200.00	1					24
20.00	1					25
25.00	1		STAT CAP	1	14	26
30.00	1					27
10.00	2					28
30.50	2					29
50.00	1		STAT CAP	1	10	30
160.00	1					31
320.00	2					32
13.00	2		STAT CAP	1	5	33
10.00	1					34
90.00	1		STAT CAP	1	10	35
20.00	1					36
20.00	1					37
90.00	1					38
20.00	1					39
10.00	2					40

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SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LOVELY-LOVELY	T-A	138.00	34.50	
2	OLIVE HILL-ASHLAND	D-U	69.00	12.00	
3	PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
4	PRINCESS-CANNONSBURG	D-U	69.00	69.00	
5	RUSSELL-RUSSELL	D-U	69.00	12.00	
6	SIDNEY-SIDNEY	D-U	69.00	12.00	
7	SLEMP-SLEMP	D-U	69.00	34.00	
8	SOUTH PIKEVILLE-PIKEVILLE	D-U	69.00	12.00	
9	STINNETT-HOSKINGSTON	D-U	161.00	34.00	12.00
10	STONE-BELFRY	T-U	138.00	69.00	46.00
11	TENTH STREET-ASHLAND	D-U	69.00	69.00	
12	THELMA-PAINTSVILLE	T-U	138.00	69.00	46.00
13	VICCO-VICCO	D-U	138.00	34.00	
14	WEST PAINTSVILLE-PAINTSVILLE	D-U	69.00	12.00	
15	WHITESBURG-WHITESBURG	D-U	69.00	12.00	
16	WILLIAMSON-S. WILLIAMSON	D-U	46.00	12.00	
17	WURTLAND-WURTLAND	D-U	69.00	12.00	
18					
19	48 STATIONS UNDER 10,000 KVA	T/D			
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SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30.00	1					1
12.50	2	1				2
25.00	1					3
20.00	1					4
20.00	1					5
20.00	1					6
31.00	2					7
25.00	1	1				8
20.00	2	1				9
50.00	1					10
20.00	1					11
70.00	1	1	STAT CAP	2	40	12
30.00	1					13
12.00	1					14
15.00	2		STAT CAP	1	13	15
11.00	2					16
20.00	1					17
						18
274.00	48					19
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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 parties, 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.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS Number (c)	LINE TRANSFORMERS Total Capacity (In MVa) (d)
1	Number at Beginning of Year	176,802	86,512	2,685
2	Additions During Year			
3	Purchases	6,185	3,293	114
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	6,185	3,293	114
6	Reductions During Year			
7	Retirements	6,138	2,049	58
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	6,138	2,049	58
10	Number at End of Year (Lines 1+5-9)	176,849	87,756	2,741
11	In Stock	4,518	904	80
12	Locked Meters on Customers' Premises	4,516		
13	Inactive Transformers on System			
14	In Customers' Use	167,723	86,692	2,657
15	In Company's Use	92	160	4
16	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	176,849	87,756	2,741

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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	$1,302,156	$1,220,484
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	611,814	
3	Fuel Related Costs		
4	Operation of Facilities	1,327,854	
5	Fly Ash and Sulfur Sludge Removal		
6	Difference in Cost of Environmentally Clean Fuels		
7	Replacement Power Costs	226,264	
8	Taxes and Fees	31,344	
9	Administrative and General		
10	Other (Identify significant)		
11	TOTAL	$3,499,432	$1,220,484

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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 judgement 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.

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 (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	$407,704	0	0	$23,518,190	$23,518,190
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				0	0
5	Esthetic Costs				0	0
6	Additional Plant Capacity	37,064			2,160,628	
7	Miscellaneous (Identify significant)					
8	TOTAL (Total of lines 1 thru 7)	$444,768	0	0	$35,045,365	$32,884,737
9	Construction Work in Progress				304,729	304,729

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KENTUCKY POWER COMPANY
d/b/a

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

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KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER

REQUEST:

Please provide a copy of Joint Proxy Statement which addresses the change in control payments related to the CSW/AEP merger.

RESPONSE:

Attached please find a copy of the Joint Proxy Statement which addresses the CSW/AEP change in control payments.

WITNESS: RICHARD E. MUNCZINSKI

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215

April 16, 1998

Dear Shareholder:

We invite you to attend our annual meeting which will be held at The Ohio State University's Fawcett Center, 2400 Olentangy River Road, Columbus, Ohio at 9:30 a.m., local time, on May 27, 1998.

At the annual meeting, we will ask you to approve:

- an increase in the number of authorized shares of AEP common stock from 300,000,000 to 600,000,000; and
- our using these shares to complete the transaction with Central and South West Corporation, as described in the merger agreement we have with them.

We can complete the transaction with Central and South West only if you approve these two actions. As a result of the transaction, Central and South West Corporation stockholders will receive 0.60 of a share of AEP common stock in exchange for each of their shares of Central and South West common stock. Following the merger, the current stockholders of Central and South West Corporation will hold approximately 40.1% of the issued and outstanding AEP common stock.

The Board of Directors of AEP has determined that the merger is fair and in your best interests. The Board has unanimously approved the merger agreement and the transactions contemplated by the merger agreement.

At the meeting, we will also ask you to elect directors and ratify the appointment of Deloitte & Touche LLP as independent auditors for 1998.

The merger is described in the accompanying Joint Proxy Statement/Prospectus. Additional information concerning the related transactions accompanies this letter. Please read these materials carefully.

See "Risk Factors" beginning on page 20 for certain matters you should consider.

During the course of the meeting there will be the usual time for discussion of the items on the agenda and for questions regarding AEP's affairs. Directors and officers will be available to talk individually with shareholders before and after the meeting.

Your participation in the annual meeting, in person or by proxy, is important. Please mark, date, sign and return the enclosed proxy as soon as possible, whether or not you plan to attend the meeting or, if you prefer you may vote your shares by telephone or internet by following the instructions on the proxy card. If you have any questions regarding the proposed transaction, please call Morrow & Co., Inc., our proxy solicitation agent, toll free at (800) 566-9061.

Thank you and I look forward to seeing you at the meeting.

Sincerely,

E. Linn Draper, Jr.
Chairman of the Board, President
and Chief Executive Officer

The Securities and Exchange Commission and state securities regulators have not approved the Merger described in this Joint Proxy Statement/Prospectus or the Company Common Stock to be issued in the Merger, and they have not determined whether this Joint Proxy Statement/Prospectus is truthful or complete. Furthermore, the Securities and Exchange Commission has not determined the fairness or merits of the Merger. Any representation to the contrary is a criminal offense.

This Joint Proxy Statement/Prospectus is dated April 16, 1998 and is first being mailed to shareholders on or about April 20, 1998.

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215

Notice of Annual Meeting of Shareholders

April 16, 1998

Dear Shareholder:

THE ANNUAL MEETING of shareholders of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company" or "AEP"), will be held at The Ohio State University's Fawcett Center, 2400 Olentangy River Road, Columbus, Ohio at 9:30 a.m., local time, on May 27, 1998 for the following purposes:

1. To vote upon the issuance by AEP of shares of its Common Stock, par value $6.50 per share ("AEP Common Stock"), to the stockholders of Central and South West Corporation ("CSW") pursuant to the Agreement and Plan of Merger dated as of December 21, 1997, which appears as Annex I to the accompanying Joint Proxy Statement/Prospectus, providing for the merger of Augusta Acquisition Corporation, a wholly-owned subsidiary of the Company, with and into CSW;
2. To approve the amendment of the Company's Restated Certificate of Incorporation to increase the number of authorized shares of AEP Common Stock from 300,000,000 shares to 600,000,000 shares;
3. To elect 11 directors of the Company, to hold office until the next annual meeting of the Company's shareholders and until their successors are duly elected;
4. To approve the firm of Deloitte & Touche LLP as independent auditors for 1998; and
5. To consider and act on such other matters as may properly come before the meeting.

The Board of Directors has fixed the close of business on April 8, 1998, as the record date for the determination of shareholders entitled to notice of and to vote at the meeting.

The Company's audited financial statements and management's discussion and analysis of results of operations and financial condition were mailed to you the last week of March, 1998. A copy of such information will be provided by first-class mail without charge to any shareholder, including any beneficial owner, upon oral or written request. Requests should be directed to Investor Relations, at the Company's address set forth above or by phoning (800) 237-2667. You will receive the Company's summary annual report under separate cover.

If you plan to attend the meeting and are a shareholder of record, please mark the "Annual Meeting" box on your proxy card. An admission ticket is included with the proxy card for each shareholder of record. However, if your shares are not registered in your own name, please advise the shareholder of record (your bank, broker, etc.) that you wish to attend. That firm must provide you with evidence of your ownership which will enable you to gain admittance to the meeting.

Your vote is very important. Please sign and date the enclosed proxy card and return it promptly in the enclosed return envelope, whether or not you expect to attend the meeting. This year, record holders of AEP Common Stock can also vote their shares by using a toll-free telephone number or the internet. Instructions for using these convenient new services are set forth on the enclosed proxy card.

You may revoke your proxy and vote in person if you decide to attend the meeting.

If you are planning to attend the meeting, please indicate this when you vote.

By Action of the Board of Directors,

G.P. Maloney
Secretary

Columbus, Ohio
April 16, 1998

CENTRAL AND SOUTH WEST CORPORATION
1616 Woodall Rodgers Freeway
Dallas, Texas 75202-1234

April 16, 1998

To Our Stockholders:

We invite you to attend our annual meeting which will be held at 10:30 a.m., local time, on Thursday, May 28, 1998 at the Dallas Museum of Art, 1717 North Harwood Street, Dallas, Texas.

At the annual meeting, we will ask you to vote on a proposal to approve the merger of a subsidiary of American Electric Power Company, Inc. into Central and South West Corporation. As a result of the merger, you will receive 0.60 of a share of AEP common stock for each share of CSW common stock owned by you. Following the Merger, the current stockholders of CSW will hold approximately 40.1% of the issued and outstanding AEP Common Stock.

We can complete the merger only if certain conditions are satisfied, including obtaining your approval and satisfying certain regulatory requirements.

The accompanying Joint Proxy Statement/Prospectus includes a summary of the terms of the Merger and certain other information relating to the Merger. Please read this material carefully.

See "Risk Factors" beginning on page 20 for certain matters you should consider.

Your Board of Directors has determined that the Merger Agreement and the transactions contemplated thereby are fair, and in your best interests and recommends that you vote FOR the approval of the Merger Agreement.

At the meeting, we will also ask you to elect directors and ratify the appointment of the firm of Arthur Andersen LLP as independent public accountants for 1998.

The formal notice of the annual meeting is attached, and a form of proxy is enclosed for your use. Whether or not you expect to attend the meeting, it is very important that your shares be represented, and it would therefore be helpful if you would return your signed and dated proxies promptly. If you have any questions regarding the proposed transaction, please call investor services at CSW at (888) 279-1100 (toll free).

I look forward to seeing you at the meeting.

Sincerely,

E.R. Brooks

E.R. BROOKS
Chairman and Chief Executive Officer

The Securities and Exchange Commission and state securities regulators have not approved the Merger described in this Joint Proxy Statement/Prospectus or the AEP common stock to be issued in the Merger, and they have not determined whether this Joint Proxy Statement/Prospectus is truthful or complete. Furthermore, the Securities and Exchange Commission has not determined the fairness or merits of the Merger. Any representation to the contrary is a criminal offense.

This Joint Proxy Statement/Prospectus is dated April 16, 1998 and is first being mailed to shareholders on or about April 20, 1998.

CENTRAL AND SOUTH WEST CORPORATION
1616 Woodall Rodgers Freeway
Dallas, Texas 75202-1234

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of Central and South West Corporation, a Delaware corporation ("CSW"), will be held at the Dallas Museum of Art, 1717 North Harwood Street, Dallas, Texas on Thursday, May 28, 1998 at 10:30 a.m., local time, for the following purposes:

1. To consider and vote upon a proposal to approve and adopt the Agreement and Plan of Merger dated as of December 21, 1997 (the "Merger Agreement"), attached as Annex I to the accompanying Joint Proxy Statement/Prospectus, providing for the merger (the "Merger") of Augusta Acquisition Corporation, a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), with and into CSW and the other transactions contemplated thereby;

2. To elect three directors who will constitute Class II of the Board of Directors and two directors who will be included in Class III of the Board of Directors;

3. To approve the appointment of Arthur Andersen LLP as independent public accountants for 1998; and

4. To transact such other business as may properly come before the meeting or any adjournment thereof.

Approval and adoption of the Merger Agreement and the transactions contemplated thereby requires the affirmative vote of a majority of the outstanding shares of CSW's Common Stock entitled to vote thereon.

Stockholders of CSW are not entitled to appraisal rights in connection with the Merger.

The enclosed proxy card will enable you to vote your shares on the matters to be considered at the annual meeting. All you need to do is mark the proxy card to indicate your vote, date and sign the proxy card, and then return it promptly in the self-addressed stamped envelope provided. The giving of the proxy will not affect your right to attend the meeting, or, if you choose to revoke the proxy, your right to vote in person.

The Board of Directors has fixed the close of business on April 8, 1998 as the record date for determination of stockholders entitled to notice of and to vote at the annual meeting.

By Order of the Board of Directors

Kenneth C. Raney, Jr.

KENNETH C. RANEY, JR.
Secretary

April 16, 1998

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Q: Should CSW stockholders or AEP shareholders send in their stock certificates now?

A: No. If you are a CSW stockholder, after the merger is completed you will receive written instructions for exchanging your CSW common shares for AEP common shares (and your cash payment in lieu of any fractional AEP common share). If you are an AEP shareholder, you should retain your certificates, as you will continue to hold the AEP shares you currently own.

Q: What happens to my future dividends?

A: AEP and CSW each plan to continue to pay dividends on their common stock until the closing of the merger at approximately the same times and rates per share as were paid by each company during the last year. However, both the AEP Board and the CSW Board will continue to evaluate their respective financial condition and earnings. AEP does not anticipate making any changes to its dividend policy following the merger; however, the AEP Board will continue to evaluate the financial condition and earnings of AEP and its dividend policy.

Q: What are the tax consequences of the merger to shareholders?

A: The exchange of shares of CSW common stock for shares of AEP common stock in the merger will be tax-free to CSW stockholders for federal income tax purposes. Holders of CSW common stock will, however, have to pay taxes on any cash received for fractional shares.

The merger will not have any effect on AEP shareholders for federal income tax purposes.

Q: What will CSW stockholders' tax basis be in the AEP common stock they receive in the merger?

A: Your tax basis in the shares of AEP common stock will equal your current tax basis in your CSW common stock reduced by the amount of basis allocable to fractional shares.

Q: What regulatory approvals are needed?

A: Before we can complete the merger, we must, among other things:

- await the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and
- receive approvals from federal regulatory agencies, including:
  - the Securities and Exchange Commission;
  - the Nuclear Regulatory Commission; and
  - the Federal Energy Commission.
- receive approvals from state regulatory agencies, including regulators in:
  - Arkansas;
  - Louisiana;
  - Oklahoma; and
  - Texas.

Q: When do you expect the merger to be completed?

A: We hope to complete the merger in the first half of 1999. We are working toward completing the merger as quickly as possible. The timing and likelihood of obtaining the regulatory approvals described above is uncertain.

Q: Who can help answer my questions?

A: If you are an AEP shareholder and you have more questions about the merger, you should contact:

American Electric Power Company, Inc.
Shareholder Relations Department
1 Riverside Plaza
Columbus, Ohio 43215
Telephone: (800) 237-2667
Fax: (614) 223-2807

or

Morrow & Co, Inc., the
proxy solicitor, who may be called toll-free at (800) 566-9061

If you are a CSW stockholder and you have more questions about the merger, you should contact:

Central and South West Corporation
Investor Services Department
1616 Woodall Rodgers Freeway
Dallas, Texas 75202
Telephone: (888) 279-1100 (toll free)
Fax: (214) 777-2829

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JOINT PROXY STATEMENT/PROSPECTUS SUMMARY

This summary highlights selected information from this document and may not contain all of the information that is important to you. To understand the merger fully and for a more complete description of the legal terms of the merger, you should read carefully this entire document and the documents referred to in "Where You Can Find More Information" (page 137). The merger agreement is attached as Annex I to this document. We encourage you to read the merger agreement. It is the legal document that governs the merger.

The Companies (page 29)

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215-2373
(614) 223-1000

AEP is one of the nation's largest public utility holding companies, providing energy to 2.9 million customers. Through its domestic electric utility subsidiaries, AEP primarily generates, transmits, distributes or sells electric energy in portions of the states of Ohio, Indiana, Kentucky, Michigan, Tennessee. Virginia and West Virginia. Substantially all of the operating revenues of AEP and its subsidiaries are derived from selling electricity to customers. AEP also has holdings in the United Kingdom and China. Wholly owned subsidiaries provide power engineering, consulting, telecommunications and management services around the world.

Central and South West Corporation
1616 Woodall Rodgers Freeway
Dallas, Texas 75202-1234
(214) 777-1000

CSW is a global, diversified public utility holding company based in Dallas. CSW owns four domestic electric utility subsidiaries serving 1.7 million customers in portions of the states of Texas, Oklahoma, Louisiana and Arkansas and a regional electricity company in the United Kingdom. CSW owns other international energy operations and non-utility subsidiaries involved in energy-related investments, telecommunications, energy efficiency services (such as engineering design, equipment procurement and performance monitoring) and financial transactions.

The Meetings (pages 22 and 26)

Time, Place and Date of Meetings. The annual meeting of shareholders of AEP will be held at The Ohio State University's Fawcett Center. 2400 Olentangy River Road, Columbus, Ohio, at 9:30 a.m., local time, on Wednesday, May 27, 1998.

The annual meeting of stockholders of CSW will be held at 10:30 a.m., local time, on Thursday, May 28, 1998, at the Dallas Museum of Art, 1717 North Harwood Street, Dallas, Texas.

Matters to Be Considered at the Meetings. AEP Meeting. At the AEP meeting, we will ask the AEP shareholders (1) to approve an increase in the number of authorized shares of AEP Common Stock from 300,000,000 to 600,000,000, (2) to approve the use of AEP shares to complete the transaction with CSW, (3) to elect directors for AEP and (4) to approve independent auditors for AEP.

CSW Meeting. At the CSW meeting, holders of shares of common stock of CSW will be asked to (1) approve the merger agreement providing for the merger, (2) elect directors for CSW and (3) approve independent public accountants for CSW.

Votes Required. AEP. The issuance of AEP shares to holders of CSW shares in the merger requires the affirmative vote of a majority of the votes cast on the proposal, provided that the total votes cast on the proposal represent a majority of the outstanding AEP shares. The Charter Amendment requires the affirmative vote of a majority of the total outstanding AEP shares. AEP directors will be elected by a plurality of the votes cast at the AEP meeting. Approval of the independent auditors of AEP requires the affirmative vote of a majority of the AEP shares present or represented by proxy at the AEP meeting.

CSW. Approval of the merger agreement requires the affirmative vote of a majority of the total outstanding CSW shares. CSW directors will be elected by a plurality of the votes cast at the CSW meeting. This means that the persons (up to the number of Board seats to be filled) who receive more votes than those cast for other candidates win the election. Approval of the independent public accountants of CSW requires the favorable vote of a majority of the CSW shares present or represented by proxy at the CSW meeting.

Voting (pages 23 and 26)

AEP. AEP shareholders will have one vote at the AEP meeting for each AEP share held of record on April 8, 1998:

- to approve the issuance of AEP shares to holders of CSW shares in the merger;
- to approve the amendment to the AEP certificate of incorporation; and
- to approve Deloitte & Touche LLP as independent auditors for AEP for 1998.

Voting is, however, cumulative for the election of AEP directors. This means you have the right to cast a total number of votes equal to the number of shares you hold multiplied by the number of directors to be elected. You may cast all your votes for one candidate, or you may distribute these votes among the candidates.

Example: If you held 10 AEP shares on April 8, 1998 you will have a total of 110 votes that you may cast all for one candidate or distribute among the 11 candidates as you wish.

CSW. CSW stockholders will have one vote at the CSW meeting for each CSW share held of record on April 8, 1998:

- to approve the merger agreement;
- to approve Arthur Andersen LLP as independent public accountants for CSW for 1998; and
- to elect directors.

The Record Dates for Voting at the Meetings (pages 23 and 26)

AEP.

The close of business on April 8, 1998 was the record date for determining which holders of AEP capital stock are entitled to vote at the AEP meeting. At the record date, there were 190,378,571 AEP shares entitled to vote at the AEP meeting.

CSW.

The close of business on April 8, 1998 was the record date for determining which holders of CSW capital stock are entitled to vote at the CSW meeting. At the record date, there were 212,281,477 CSW shares entitled to vote at the CSW meeting.

Security Ownership of Management (pages 117 and 121)

As of January 1, 1998, directors and executive officers of AEP and their affiliates beneficially owned an aggregate of approximately 146,369 shares (less than 1%) of the outstanding AEP shares. As of December 31, 1997, directors and executive officers of CSW and their affiliates beneficially owned an aggregate of approximately 486,165 shares (less than 1%) of the outstanding CSW shares.

What You Will Receive in the Merger (page 31)

AEP Shareholders:

After the merger, each AEP share will remain outstanding and will represent one share of the combined companies, which will continue under the name "American Electric Power Company, Inc."

CSW Stockholders:

Each CSW share will be converted into the right to receive 0.60 of an AEP share from AEP and CSW will become a wholly-owned subsidiary of AEP.

Assuming that there are 190,378,571 AEP shares and 212,281,477 CSW shares outstanding immediately before the closing of the merger, the number of AEP shares to be issued to the holders of CSW shares in the merger would be 127,368,886, which would represent approximately 40.1% of the outstanding AEP shares immediately after the closing of the merger.

Recommendations of the Boards of Directors (page 44)

AEP. **AEP's Board of Directors has approved the merger agreement, the issuance of AEP shares to holders of CSW shares in the merger and the amendment to the AEP certificate of incorporation. The AEP Board of Directors recommends that AEP shareholders vote FOR the share issuance and the charter amendment.**

CSW. **CSW's Board of Directors has determined that the terms of the merger agreement and the transactions contemplated thereby are fair to, and in the best interests of, CSW and its stockholders and recommends that CSW stockholders vote FOR the approval of the merger agreement.**

Background of the Merger

The chief executive officers of AEP and CSW had informal discussions on several occasions from January 1997 to March 1997 regarding a merger of the companies. With CSW's stock price depressed in late April 1997 as a result, in the opinion of CSW management, of adverse action by the Texas Public Utility Commission, CSW management terminated discussions with AEP.

From May through September 1997, CSW management continued to explore a variety of strategic alternatives. As part of this analysis, CSW management, in consultation with its advisers, developed a list of screening criteria for use in analyzing potential merger partners. CSW also considered other strategic alternatives which could be pursued without a business combination. At a meeting of the CSW Board of Directors on September 27, 1997, management recommended to the CSW Board of Directors that CSW seek a merger with a partner that could enhance CSW's ability to implement its long-term vision. The CSW Board of Directors unanimously authorized CSW management to pursue its search for an appropriate merger partner while continuing to evaluate CSW's stand-alone options.

In September 1997, the chief executive officers of AEP and CSW resumed their discussions regarding a stock-for-stock merger. During the ensuing months, CSW's management also held preliminary discussions, and exchanged non-public information, with three other electric utilities regarding a possible business combination and continued to evaluate other stand-alone alternatives. CSW management met with the CSW Board of Directors and a committee of the CSW Board of Directors on many occasions during October-December 1997 to update the directors and receive direction on the course of their discussions.

On November 24, 1997, CSW management and CSW's advisers met with a committee of the CSW Board to discuss the progress of the strategic alternative evaluation process. The committee authorized CSW management to send to four strategic merger candidates a letter requesting each to advise CSW as to whether, and on what terms, it was interested in pursuing a strategic combination with CSW. On December 11, 1997, CSW received affirmative responses to the request letters from AEP and two of the three other companies.

On December 12, 1997, CSW management and advisers met with a committee of the CSW Board of Directors to discuss the responses and the status of the strategic merger candidate evaluation process. After analyzing the responses and CSW's other stand-alone alternatives, the committee determined that AEP appeared to be the best strategic merger partner for CSW and that a merger with AEP on the right terms would be more likely to restore and enhance long-term stockholder value than any of the other merger or stand-alone strategic alternatives.

Following negotiations between Dr. Draper and Mr. Brooks, CSW and AEP agreed to proceed with merger negotiations on the basis of a proposed exchange ratio of 0.60 of an AEP share for each CSW share. The Boards of Directors of both companies approved the merger agreement in meetings on December 21, 1997, and the merger agreement was signed that afternoon.

Opinions of Financial Advisors (pages 47 and 54)

AEP. In deciding to approve the merger, one of the factors that AEP's Board of Directors considered was the opinion of its financial advisor, Salomon Brothers Inc, now doing business as Salomon Smith Barney, that, as of December 21, 1997 and based upon and subject to the considerations set forth in such opinion, the consideration to be paid by AEP in connection with the merger was fair to AEP from a financial point of view. **AEP urges its shareholders to read the entire Salomon Smith Barney opinion attached as Annex II to this Joint Proxy Statement/Prospectus carefully.**

CSW. Similarly, in deciding to approve the merger, one of the factors that the CSW Board of Directors considered was the opinion (which opinion has been reissued as of the date of this Joint Proxy Statement/Prospectus) of its financial advisor, Morgan Stanley & Co. Incorporated, that as of December 21, 1997, and the date of this Joint Proxy Statement/Prospectus, the exchange ratio was fair from a financial point of view, to the holders of CSW Shares. **CSW urges its stockholders to read the entire Morgan Stanley opinion attached as Annex III to this Joint Proxy Statement/Prospectus carefully.**

Interests of Certain Persons in the Merger (page 61)

In considering the CSW Board of Directors' recommendation that CSW stockholders vote in favor of the merger, CSW shareholders should be aware that a number of CSW's officers and directors have severance agreements, retention incentives or benefit plans that give them interests in the merger that are different from, or in addition to, other CSW shareholders. The total amount that may be payable to CSW's officers and directors in connection with the merger due to severance and retention arrangements is approximately $48.4 million, plus any additional payments that may be necessary to cover excise tax liabilities in connection with such payments. In order to encourage key executives to stay, and for other business reasons, CSW and AEP are currently evaluating certain modifications to the severance agreements and retention incentives which are not expected to result in an increase in such payments.

Conditions to the Merger (page 95)

AEP and CSW will not complete the merger unless a number of conditions are satisfied or, if permitted, waived by them. These include:

- AEP shareholders must approve the issuance of AEP shares in the merger and the amendment to the AEP certificate of incorporation (which condition may not be waived);
- CSW stockholders must approve and adopt the merger agreement (which condition may not be waived);
- each party's representations and warranties contained in the merger agreement must continue to be accurate;
- each party must perform its obligations under the merger agreement;
- there cannot be any injunction that prohibits the merger (which condition may not be waived);
- the relevant governmental authorities must approve the merger without the imposition of conditions that could reasonably be expected to have a material adverse effect on the combined company;
- there cannot be any law or order imposed by a governmental authority that requires the divestiture of a substantial portion of the generating assets of CSW or AEP;
- AEP and CSW must receive legal opinions as to the tax free nature of the merger;
- AEP and CSW must receive opinions dated as of the date of this Joint Proxy Statement/ Prospectus of Salomon Smith Barney and Morgan Stanley confirming their original fairness opinions (which opinions have been received);
- AEP and CSW must receive letters from AEP's and CSW's independent accountants stating that the merger will qualify for pooling of interests accounting treatment;
- the New York Stock Exchange must authorize listing of the AEP shares to be issued in the merger; and
- the registration statement on Form S-4 registering the AEP shares to be issued in the merger must be declared effective (which registration statement has been declared effective).

Regulatory Approvals (page 100)

We must receive the approvals of federal and state regulatory agencies before we can complete the merger. At the federal level, these approvals include approval of the Securities and Exchange Commission, the Nuclear Regulatory Commission and the Federal Energy Regulatory Commission. We must also complete the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. At the state level, we must receive approvals from regulators in Arkansas, Louisiana, Oklahoma and Texas. We also require the approval or non-opposition of certain state regulatory commissions.

Termination of the Merger Agreement (page 96)

AEP and CSW mutually can agree to terminate the merger agreement at any time, whether before or after the receipt of stockholder approval, without completing the merger. Either one of them can terminate the merger agreement if:

- the merger is not completed by December 31, 1999, although this deadline will be extended to June 30, 2000 if the completion of the merger is delayed only because certain governmental approvals have not been received;
- the shareholders of AEP do not approve the issuance of AEP shares in the merger and the amendment of the AEP certificate of incorporation or the stockholders of CSW do not approve and adopt the merger agreement;
- a governmental authority, such as a court, permanently prohibits the merger;
- the board of directors of the other company
  - withdraws or modifies in any adverse manner its approval or recommendation of the merger.
  - fails to reaffirm its approval or recommendation of the merger if the terminating company requests it,
  - approves or recommends any acquisition of such other company by a third party (other than pursuant to the merger agreement), or
  - approves or recommends a sale of a material portion of such other company's capital stock or assets to a third party (other than pursuant to the merger agreement);
- the board of directors of the other company determines, under certain circumstances, that the board's fiduciary obligations require acceptance of an offer from a third party to enter into an alternative acquisition transaction;
- if a third party acquires greater than 50% of the voting power of the other company or if the individuals who make up the current board of directors of the other party (or nominees whom they have approved) of the other company no longer constitute a majority of the board; or
- the other company breaches or fails to comply with any of its material representations, warranties or obligations under the merger agreement, unless such breach or failure to comply can be cured and the other company continues to use reasonable efforts to remedy such breach or failure to comply.

Termination Fees and Expenses (page 97)

Either AEP or CSW will be required to pay the other a fee of $225 million plus expenses of up to a total of $20 million if:

- the merger is not completed by December 31, 1999, although this deadline will be extended to June 30, 2000 if the completion of the merger is delayed only because certain governmental approvals have not been received, and:
  - at that time, there is an offer from a third party to enter into another transaction with it, and,
  - within 18 months after the termination, it enters into an agreement with the third party for an acquisition;
- it terminates the merger agreement to accept a superior proposal from a third party:
  - after its board of directors determines in good faith that its fiduciary obligations under applicable law require them to accept the superior proposal, and,
  - within 18 months of the termination, it enters into an agreement with the third party for an acquisition;
- it fails to obtain the shareholders approval for the merger, and,

- at that time, there is an offer from a third party to enter into an acquisition with it and.
- within 18 months of the termination, it enters into an agreement with the third party for an acquisition;

- its board of directors withdraws its approval of the merger, and
  - at that time, there is an offer from a third party to enter into an acquisition with it and,
  - within 18 months of the termination, it enters into an agreement with the third party for an acquisition;
- the merger agreement is terminated by the other party due to a breach by it and,
  - at the time of termination, there is an offer from a third party to enter into another transaction with it and,
  - within 18 months of the termination, it enters into an agreement with the third party for an acquisition; or
- a third party acquires greater than 50% of its voting power or the individuals who make up its current board of directors no longer constitute a majority of the board.

Either AEP or CSW will be required to pay the other a fee of $20 million if:

- it terminates the merger agreement to accept a superior proposal from a third party after its board of directors determines in good faith that its fiduciary obligations under applicable law require the board to accept the superior proposal;
- the merger agreement is terminated by reason of its material breach or failure to comply with any of its representations, warranties or obligations under the merger agreement;
- its board of directors withdraws its approval of the merger or its favorable recommendation of the merger; or
- the merger agreement is terminated by the other party because a third party acquires greater than 50% of its voting power or if the individuals who make up its current board of directors no longer constitute a majority of the board.

In no event will the fees and expenses payable by either party as described above exceed $245 million.

No Appraisal Rights (page 85)

Neither CSW stockholders nor AEP shareholders are entitled to dissenters' appraisal rights in connection with the merger.

U.S. Federal Income Tax Consequences (page 59)

The merger is structured so that none of AEP, its merger subsidiary, CSW, CSW stockholders or AEP shareholders will recognize any gain or loss for federal income tax purposes in connection with the merger (except for taxes payable because of cash received instead of fractional AEP Shares by CSW stockholders). The merger is conditioned on receipt of legal opinions that this is the case.

AEP has received from its counsel, Simpson Thacher & Bartlett, an opinion to the effect that the merger will be treated for United States federal income tax purposes as a reorganization as defined in the Internal Revenue Code, that AEP, its merger subsidiary and CSW each will be a party to the reorganization as defined in the Internal Revenue Code and that AEP, its merger subsidiary and CSW will not recognize any gain or loss as a result of the merger. CSW has received from its tax counsel, Christy & Viener, an opinion to the effect that the merger will be treated for United States federal income tax purposes as a reorganization as defined in the Internal Revenue Code, that AEP, its merger subsidiary and CSW each will be a party to the reorganization as defined in the Internal Revenue Code, and that stockholders of CSW will not recognize any gain or loss upon the receipt of AEP shares for their CSW shares, other than with respect to cash received in lieu of fractional shares.

Under the terms of the merger agreement AEP and/or CSW may waive the requirement that such parties receive the bring-down opinions of tax counsel described above at closing. If the receipt of such tax opinions at closing is waived by either party, AEP and CSW will recirculate this Joint Proxy Statement/Prospectus to disclose any such waiver and all related material disclosure, including risks to investors, and resolicit the votes of the respective stockholders of AEP and CSW.

Tax matters can be complicated and the tax consequences of the merger to you will depend on the facts of your own situation. You should consult your own tax advisors to fully understand the tax consequences of the merger to you.

Comparison of Shareholder Rights (page 77)

In the merger, if you are a CSW stockholder, you will receive AEP shares and become an AEP shareholder. There are numerous differences between the rights of a stockholder in CSW, a Delaware corporation, and the rights of a shareholder in AEP, a New York corporation, including classification of directors, cumulative voting for directors, the ability of stockholders to take action without a meeting and preemptive rights of stockholders in connection with the issuance of shares. If you are an AEP shareholder, there will be no change in your rights as an AEP shareholder after the merger.

Forward-Looking Statements May Prove Inaccurate (page 19)

AEP and CSW have made forward-looking statements in this document that are subject to certain risks and uncertainties. Forward-looking statements include the information concerning possible or assumed future results of operations of AEP, CSW and the combined company as well as statements preceded by, followed by or that include the words "believes," "expects," "anticipates," "intends," or similar expressions. You should understand that certain important factors, in addition to those discussed elsewhere in this document and in the documents that are incorporated herein by reference, could affect the future results of the combined companies and could cause those results to differ materially from those expressed in our forward-looking statements.

Directors of AEP Following the Merger (page 62)

In the merger agreement, AEP and CSW have agreed that the Board of Directors of AEP immediately following the merger will consist of 15 members and will be reconstituted to include all then current board members of AEP, Mr. E.R. Brooks (the current Chairman of CSW) and four additional outside directors of CSW to be nominated by AEP.

COMPARATIVE PER SHARE DATA

The following table sets forth certain historical per share data of AEP and CSW and combined per share data on an unaudited pro forma basis after giving effect to the Merger as if it had occurred on January 1, 1995 on a pooling-of-interests basis assuming that 0.60 of an AEP share was issued in exchange for each CSW share outstanding. This data should be read in conjunction with the selected historical audited and unaudited financial data and the historical audited and unaudited financial statements of AEP and CSW and the notes thereto that are incorporated herein by reference. The pro forma combined per share information of AEP and CSW is derived from the unaudited pro forma combined condensed financial statements and notes thereto included elsewhere in this Joint Proxy Statement/Prospectus. The pro forma comparative per share data does not purport to represent what the financial position or results of operations of AEP would actually have been had the transactions identified above occurred at the beginning of the relevant periods or to project AEP's financial position or results of operations for any future date or period. The data set forth below should be read in conjunction with the pro forma financial statements and the separate historical financial statements and notes thereto of AEP and CSW, included elsewhere in, or incorporated by reference into, this Joint Proxy Statement/Prospectus.

	AEP Historical per Share	CSW Historical per Share	Pro Forma Combined per AEP Share	Pro Forma Equivalent Combined per CSW Share
Book value per share:				
Year ended December 31, 1997	$ 24.62	$ 16.76	$25.79	$ 15.47
Cash Dividends Declared per share:				
Year ended December 31, 1995	$ 2.40	$ 1.72	$ 2.58(a)	$ 1.55(a)
Year ended December 31, 1996	2.40	1.74	2.59(a)	1.55(a)
Year ended December 31, 1997	2.40	1.74	2.60(a)	1.56(a)
Income per share from continuing operations (basic and diluted):				
Year ended December 31, 1995	$ 2.85	$ 1.97	$ 3.02	$ 1.81
Year ended December 31, 1996	3.14	1.43	2.84	1.70
Year ended December 31, 1997	3.28	1.55	3.00	1.80
Dividend payout ratio:				
Year ended December 31, 1997	88.7%(b)	241.7%(b)	123.9%(b)	123.9%(b)

(a) The pro forma combined dividends per share were based on the sum of the historical dividends declared by AEP and CSW divided by the pro forma average number of AEP shares outstanding. The pro forma average number of AEP shares was calculated by multiplying the average number of outstanding CSW shares during the year by the exchange ratio and adding the result to the average number of outstanding AEP shares during the year. The pro forma combined dividends per share are not necessarily indicative of the level of dividends after the consummation of the merger. The current annual dividend rate per AEP share is $2.40. AEP does not currently anticipate making any changes to its dividend. However, the AEP Board of Directors will continue to evaluate the financial condition and earnings of AEP and the continuing appropriateness of the dividend. If the pro forma combined dividends per share were based on AEP's current annual dividend rate of $2.40 per share, the pro forma combined dividends per AEP share would be $2.40 for each of the years ended December 31, 1995, 1996 and 1997 and the pro forma equivalent combined dividend per CSW share would be $1.44 for each of the years ended December 31, 1995, 1996 and 1997.

(b) The dividend payout ratio before an extraordinary loss from UK windfall tax was 73.1% for AEP and 112.3% for CSW and 86.6% for pro forma combined per AEP share and pro forma equivalent combined per CSW share.

See "Notes to Selected Historical and Unaudited Pro Forma Combined Condensed Financial Data" on page 18.

COMPARATIVE MARKET PRICE INFORMATION

AEP. The AEP shares are listed for trading on the New York Stock Exchange, Inc. ("NYSE") under the symbol "AEP." The following table sets forth, for the fiscal quarters indicated, the dividends paid and the high and low sales prices of AEP shares as reported on the NYSE Composite Transactions, in each case based on published financial sources.

	AEP		
	High	**Low**	**Dividends**
1996			
First Quarter	44¾	40⅛	0.60
Second Quarter	42¾	38⅝	0.60
Third Quarter	43⅛	40	0.60
Fourth Quarter	42½	39½	0.60
1997			
First Quarter	43 3/16	40	0.60
Second Quarter	42½	39⅛	0.60
Third Quarter	46⅝	41½	0.60
Fourth Quarter	52	45¼	0.60
1998			
First Quarter	51 11/16	47 13/16	0.60
Second Quarter (through April 16, 1998)	50¾	48	N.A.

CSW. The CSW shares are listed for trading on the NYSE and the Chicago Stock Exchange under the symbol "CSR." The following table sets forth, for the fiscal quarters indicated, the dividends paid and the high and low sales prices of CSW shares as reported on the NYSE Composite Transactions, in each case based on published financial sources.

	CSW		
	High	**Low**	**Dividends**
1996			
First Quarter	28½	26⅜	0.435
Second Quarter	28⅞	26½	0.435
Third Quarter	28½	25¾	0.435
Fourth Quarter	28	25½	0.435
1997			
First Quarter	26	20¾	0.435
Second Quarter	22¼	18	0.435
Third Quarter	22 9/16	19½	0.435
Fourth Quarter	27½	20	0.435
1998			
First Quarter	27⅞	26¼	0.435
Second Quarter (through April 16, 1998)	27¼	26 9/16	N.A.

Equivalent Per Share Data. The information presented in the table below represents closing sale prices reported on the NYSE Composite Transactions for both AEP shares and CSW shares, on December 19, 1997, the last trading day immediately preceding the public announcement of the proposed merger, and on April 16, 1998, the last practicable day for which closing sale prices were available at the time of the mailing of this Joint Proxy Statement/Prospectus, as well as the "equivalent per share price" of CSW shares on such dates. AEP and CSW shareholders should obtain current market quotations for the AEP shares and the CSW shares. The "equivalent per share price" of CSW shares represents the closing sale price per share reported on the NYSE Composite Transactions for AEP shares at such specified date, multiplied by the exchange ratio of 0.60.

	AEP Share Price	CSW Share Price	CSW Equivalent Per Share Price
December 19, 1997	$ 52	$ 26	$ 31.20
April 16, 1998	$48.3125	$26.875	$28.9875

Following the consummation of the merger, CSW shares will cease to be traded on the NYSE and the Chicago Stock Exchange.

SELECTED HISTORICAL FINANCIAL DATA

AEP and CSW are providing the following financial information to aid you in your analysis of the financial aspects of the merger. This information is only a summary and you should read it in conjunction with the historical financial statements of AEP and CSW and the related notes contained in the annual reports and other information that AEP and CSW have previously filed with the SEC. See "Where You Can Find More Information" on page 137.

SELECTED HISTORICAL FINANCIAL DATA OF AEP
(in millions—except per share amounts)

	Year Ended December 31,				
	1993	1994	1995	1996	1997
Income Statements Data					
Operating Revenues	$5,269	$5,505	$5,670	$5,849	$6,161
Operating Expenses	4,340	4,573	4,705	4,841	5,177
Operating Income	929	932	965	1,008	984
Income Before Extraordinary Item	354	500	530	587	620
Extraordinary Loss—U.K. Windfall Tax	—	—	—	—	(109)
Net Income	354	500	530	587	511
Earnings per Common Share:					
Before Extraordinary Item	$ 1.92	$ 2.71	$ 2.85	$ 3.14	$ 3.28
Extraordinary Loss	—	—	—	—	(0.58)
Net Income	$ 1.92	$ 2.71	$ 2.85	$ 3.14	$ 2.70
Dividends Declared per Common Share	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40

	December 31,				
	1993	1994	1995	1996	1997
Balance Sheets Data					
Total Assets	$15,359	$15,736	$15,900	$15,883	$16,615
Capitalization:					
Long-term Debt (a)	$ 4,995	$ 4,980	$ 5,057	$ 4,884	$ 5,424
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	268	233	148	90	47
Subject to Mandatory Redemption (a)	501	590	523	510	128
Common Shareholders' Equity	4,151	4,229	4,340	4,545	4,677
Total Capitalization	$ 9,915	$10,032	$10,068	$10,029	$10,276
Obligations Under Capital Leases (a)	$ 284	$ 400	$ 405	$ 414	$ 538
Book Value per Common Share	$ 22.50	$ 22.83	$ 23.25	$ 24.15	$ 24.62

(a) Including portion due within one year.

See "Notes to Selected Historical and Unaudited Pro Forma Combined Condensed Financial Data".

Attachment 1
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SELECTED HISTORICAL FINANCIAL DATA OF CSW
(in millions—except per share amounts)

	Year Ended December 31,				
	1993	1994	1995	1996	1997
Income Statements Data					
Operating Revenues	$3,084	$3,105	$3,143	$5,155	$5,268
Operating Expenses	2,641	2,550	2,522	4,360	4,533
Operating Income	443	555	621	795	735
Income From Continuing Operations	249	369	377	297	329
Discontinued Operations	13	25	25	132	—
Income Before Extraordinary Item	262	394	402	429	329
Extraordinary Loss—U.K. Windfall Tax	—	—	—	—	(176)
Cumulative Effect of Change in Accounting Principles	46	—	—	—	—
Net Income for Common Stock	308	394	402	429	153
Earnings per Common Share (basic and diluted):					
Continuing Operations	$ 1.32	$ 1.95	$ 1.97	$ 1.43	$ 1.55
Discontinued Operations	0.07	0.13	0.13	0.64	—
Extraordinary Loss	—	—	—	—	(0.83)
Cumulative Effect of Change in Accounting Principles	0.24	—	—	—	—
Net Income	$ 1.63	$ 2.08	$ 2.10	$ 2.07	$ 0.72
Dividends Declared per Common Share	$ 1.62	$ 1.70	$ 1.72	$ 1.74	$ 1.74

	December 31,				
	1993	1994	1995	1996	1997
Balance Sheets Data					
Total Assets	$10,604	$11,066	$13,869	$13,332	$13,451
Capitalization:					
Long-term Debt (a)(b)	$ 2,769	$ 2,946	$ 3,943	$ 4,227	$ 3,937
Certain Subsidiary–obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	—	—	—	—	335
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	292	292	292	292	176
Subject to Mandatory Redemption (a)	64	36	35	34	27
Common Stockholders' Equity	2,930	3,052	3,178	3,802	3,556
Total Capitalization	$ 6,055	$ 6,326	$ 7,448	$ 8,355	$ 8,031
Book Value per Common Share	$ 15.55	$ 16.01	$ 16.48	$ 17.98	$ 16.76

(a) Including portion due within one year.
(b) Including capital lease obligations.

See "Notes to Selected Historical and Unaudited Pro Forma Combined Condensed Financial Data".

SELECTED UNAUDITED PRO FORMA COMBINED CONDENSED FINANCIAL DATA

The following selected unaudited pro forma combined condensed financial data combines the historical consolidated balance sheets and statements of income of AEP and CSW, including their respective subsidiaries, after giving effect to the merger, assuming the merger had been effective for all periods presented. This information should be read in conjunction with the historical financial statements. These statements were prepared on the basis of accounting for the merger as a pooling of interests and are based on the assumptions set forth in the notes hereto. The following information is not necessarily indicative of the financial position or operating results that would have occurred had the merger been consummated on the dates as of which, or at the beginning of the periods for which, the merger is being given effect, nor is it necessarily indicative of future operating results or financial position. See "Unaudited Pro Forma Combined Condensed Financial Statements."

	(in millions—except per share amounts) Year Ended December 31,		
	1995	1996	1997
Income Statements Data			
Operating Revenues	$ 8,761	$10,945	$11,352
Operating Expenses	7,211	9,196	9,671
Operating Income	1,550	1,749	1,681
Income From Continuing Operations	907	884	949
Discontinued Operations	25	132	—
Income Before Extraordinary Item	932	1,016	949
Extraordinary Loss—U.K. Windfall Tax	—	—	(285)
Net Income	932	1,016	664
Earnings per Common Share (basic and diluted):			
Continuing Operations	$ 3.02	$ 2.84	$ 3.00
Discontinued Operations	0.08	0.42	—
Extraordinary Loss	—	—	(0.90)
Net Income	$ 3.10	$ 3.26	$ 2.10
Dividends Declared per Common Share	$ 2.58	$ 2.59	$ 2.60

	December 31,		
	1995	1996	1997
Balance Sheets Data			
Total Assets	$29,769	$29,215	$30,066
Capitalization:			
Long-term Debt (a)(b)	$ 9,405	$ 9,525	$ 9,899
Certain Subsidiary—obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	—	—	335
Cumulative Preferred Stocks of Subsidiaries:			
Not Subject to Mandatory Redemption	440	382	223
Subject to Mandatory Redemption (a)	558	544	155
Common Shareholders' Equity	7,518	8,347	8,183
Total Capitalization	$17,921	$18,798	$18,795
Book Value per Common Share	N.A.	N.A.	$ 25.79

(a) Including portion due within one year.
(b) Including capital lease obligations.

N.A. = Not Applicable.

See "Notes to Selected Historical and Unaudited Pro Forma Combined Condensed Financial Data."

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Notes to Selected Historical and Unaudited Pro Forma
Combined Condensed Financial Data

1. Pro forma common share amounts give effect to the conversion of each outstanding CSW share into 0.60 of an AEP share as provided in the merger agreement.

2. Certain revenues, expenses, assets and liabilities of CSW have been reclassified to conform with AEP's presentation. The effects of accounting policy differences are immaterial and have not been adjusted in the selected unaudited pro forma combined condensed financial data.

3. In November 1995, CSW announced its intention to commence a tender offer for SEEBOARD plc, a regional electricity company in the United Kingdom. By April 1996 CSW acquired control of 100% of SEEBOARD plc for an aggregate adjusted purchase price of approximately $2.1 billion. The acquisition was accounted for as a purchase and SEEBOARD plc is included in CSW financial information on a consolidated basis beginning in December 1995.

4. In June 1996, CSW sold Transok, an intrastate natural gas gathering, transmission, marketing and processing company for approximately $890 million. Transok's results of operations are shown as discontinued operations in all applicable statements of income through 1996.

5. AEP and New Century Energies, Inc. acquired a regional electricity company in the United Kingdom, Yorkshire Electricity Group plc, through an equally-owned joint venture in April 1997. Total consideration paid by the joint venture was approximately $2.4 billion which was financed by a combination of equity and non-recourse debt. AEP uses the equity method of accounting for its investment in Yorkshire Electricity Group plc which is included in other property and investments. The earnings from the investment in Yorkshire Electricity Group plc excluding extraordinary items (see Note 6) are included in nonoperating income.

6. In July 1997 the British government enacted a law that imposed on certain privatized businesses a one-time windfall tax on a revised privatization value which originally had been computed in 1990. The windfall tax is actually an adjustment of the original privatization price by the U.K. government. The pro forma windfall tax liability attributable to AEP's interest in Yorkshire Electricity Group plc and CSW's interest in SEEBOARD plc of $285 million is reported as an extraordinary loss.

7. The data assumes the business combination was accounted for as a pooling of interests and was completed prior to the periods presented. Pro forma equivalent and pro forma per share amounts give effect to the conversion of each outstanding CSW share into 0.60 of an AEP share. The pro forma combined dividends per share were based on the sum of the historical dividends declared by AEP and CSW divided by the pro forma average number of AEP shares outstanding. The pro forma average number of AEP shares was calculated by multiplying the average number of outstanding CSW shares during the year by the exchange ratio and adding the result to the average number of outstanding AEP shares during the year. The pro forma combined dividends per share are not necessarily indicative of the level of dividends after the consummation of the merger. The current annual dividend rate per AEP share is $2.40. AEP does not currently anticipate making any changes to its dividend. However, the AEP Board of Directors will continue to evaluate the financial condition and earnings of AEP and the continuing appropriateness of the dividend. If the pro forma combined dividends per share were based on AEP's current annual dividend rate of $2.40 per share, the pro forma combined dividends per AEP share would be $2.40 for each of the years ended December 31, 1995, 1996 and 1997 and the pro forma equivalent combined dividend per CSW share would be $1.44 for each of the years ended December 31, 1995, 1996 and 1997.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The following statements are or may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995:

(i) Certain statements, including possible or assumed future results of operations of AEP and CSW contained in "The Merger—Background of the Merger," "The Merger—Reasons for the Merger", "The Merger—Recommendations of the Board of Directors," "The Merger—Opinion of Financial Advisor to AEP" and "The Merger—Opinion of Financial Advisor to CSW," including any forecasts, projections and descriptions of anticipated cost savings or other synergies referred to therein, and certain statements incorporated by reference from documents filed with the Securities and Exchange Commission (the "SEC") by AEP and CSW including any statements contained herein or therein regarding the development or possible or assumed future results of operations of AEP's and CSW's businesses, the markets for AEP's and CSW's services and products, anticipated capital expenditures, regulatory developments, competition or the effects of the merger of a wholly-owned subsidiary of AEP ("Sub") with and into CSW (the "Merger"),

(ii) any statements preceded by, followed by or that include the words "believes," "expects," "anticipates," "intends" or similar expressions, and

(iii) other statements contained or incorporated by reference herein regarding matters that are not historical facts.

Because such statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such forward-looking statements. AEP and CSW stockholders are cautioned not to place undue reliance on such statements, which speak only as of the date thereof.

Among the factors that could cause actual results to differ materially are: electric load and customer growth; abnormal weather conditions; available sources and cost of fuel and generating capacity; the speed and degree to which competition enters the power generation, wholesale and retail sectors of the electric utility industry; state and federal regulatory and/or legislative initiatives that increase competition, threaten cost and investment recovery and impact rate structures; the ability of the combined company to successfully reduce its cost structure; conditions imposed by regulators in connection with the regulatory approval process related to the Merger; the degree to which the combined company is able to retain and develop additional nonregulated business ventures and the results of such ventures; the economic climate and growth in the service territories of AEP and CSW following the Merger; economies generated by the Merger; inflationary trends and interest rates; and other risks detailed from time to time in the reports filed with the SEC by AEP and CSW.

The cautionary statements contained or referred to in this section should be considered in connection with any subsequent written or oral forward-looking statements that may be issued by AEP or CSW or persons acting on its or their behalf. Except for their ongoing obligations to disclose material information as required by the federal securities laws, neither AEP nor CSW undertakes any obligation to release publicly any revisions to any forward-looking statements to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

RISK FACTORS

Shareholders of AEP and stockholders of CSW should consider carefully all the information contained in this Joint Proxy Statement/Prospectus, including the following factors:

Risks Related to the Merger

Uncertainties in Integrating the Companies and Achieving Cost Savings

CSW and AEP have entered into the Agreement and Plan of Merger dated as of December 21, 1997 (the "Merger Agreement") with the expectation that the Merger will result in certain benefits, including, without limitation, cost savings, operating efficiencies, revenue enhancements and other synergies. See "The Merger — Reasons for the Merger", "— Recommendations of the Boards of Directors." Achieving the benefits of the Merger will depend in part upon the integration of the businesses of AEP and CSW in an efficient manner, and there can be no assurance that this will occur. The consolidation of operations will require substantial attention from management. Any diversion of management attention and any difficulties encountered in the transition and integration process could have a material adverse effect on the revenues, levels of expenses and operating results of the combined company. There can be no assurance that the combined company will realize any of the anticipated benefits of the Merger. For a discussion of other factors and assumptions related to the synergy estimates, see "The Merger — Reasons for the Merger", "— Recommendations of the Boards of Directors."

Necessity of Receiving Governmental Approvals Prior to the Merger

The consummation of the Merger is conditioned upon receipt of approvals of the SEC under the Public Utility Holding Company Act of 1935, as amended (the "1935 Act"), the Nuclear Regulatory Commission (the "NRC") under the Atomic Energy Act of 1954, as amended (the "Atomic Energy Act"), the Federal Energy Regulatory Commission (the "FERC") under the Federal Power Act, as amended (the "Federal Power Act"), the Federal Communications Commission (the "FCC") under the Communications Act of 1934, as amended (the "Communication Act"), and approvals of the Arkansas Public Service Commission (the "Arkansas Commission"), the Louisiana Public Service Commission (the "Louisiana Commission") and the Oklahoma Corporation Commission (the "Oklahoma Commission"), a determination by the Public Utility Commission of Texas (the "Texas Commission") that the Merger is consistent with the public interest under applicable state laws, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act"). In addition, the approval or non-opposition of certain state regulatory commissions and the SEC is also required with respect to various inter-affiliate agreements to be entered into or amended in connection with the Merger. In addition, regulatory commissions of states where AEP's and CSW's utility subsidiaries operate as well as other parties have the ability to intervene in federal and state regulatory proceedings.

There can be no assurance as to the timing of the required regulatory approvals, the ability to obtain such approvals or that such approvals will contain satisfactory terms and conditions. It is a condition to the consummation of the Merger that final orders from various federal and state commissions described above have been obtained and do not impose terms, conditions, or qualifications that, individually or in the aggregate, could reasonably be expected to have a material adverse effect on the combined company. There can be no assurance that any such approvals will be obtained, or if obtained, will not contain terms, conditions or qualifications that cause such approvals to fail to satisfy such condition to the consummation of the Merger or that such orders will not be appealed by intervenors to the appropriate courts. See "Regulatory Approvals."

Substantial Dilution of Voting Interest of AEP Shareholders

Based on the capitalization of AEP and CSW as of April 8, 1998 and that, in the merger, CSW stockholders will receive .60 (the "Exchange Ratio") of a share of common stock, par value $6.50 per share

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of AEP ("AEP Shares"), holders of AEP Shares immediately before the Merger will own securities representing approximately 59.9% of the voting power of AEP Shares immediately following consummation of Merger, without regard to shares issuable upon the exercise of options, rights or warrants. This will constitute substantial dilution of the voting interest in AEP of the AEP shareholders.

The Effect of Stock Price Fluctuations on the Consideration to be Received by the Holders of CSW Shares in the Merger

The relative prices of shares of common stock, par value $3.50 per share of CSW (the "CSW Shares") and AEP Shares at the effective time of the Merger may vary significantly from the prices as of the date of execution of the Merger Agreement, the date hereof or the date of the shareholder meetings. These variances may be due to changes in the businesses, operations, results and prospects of AEP or CSW, market assessments of the likelihood that the Merger will be consummated and the timing thereof, the effect of any conditions or restrictions imposed on or proposed with respect to the combined company by regulatory agencies in connection with or following consummation of the Merger, general market and economic conditions, and other factors. For example, between April 16, 1997 and April 16, 1998, the closing sales price of the AEP Share has ranged from a high of $52 to a low of $39⅝; the closing sales price of the CSW Shares during the same period has ranged from a high of $27 15/16 to a low of $18¼. In addition, the stock market generally has experienced significant price and volume fluctuations. These market fluctuations could have a material adverse effect on the market or liquidity of the AEP Shares. The Exchange Ratio fixes the consideration to be received by the stockholders of CSW at .60 of an AEP Share for each CSW Share, without any minimum or maximum value per share restrictions. There can be no assurance as to the market price of the AEP Shares as of the effective time of the Merger (the "Effective Time"), and therefore there is no assurance as to the value of the consideration to be received by the CSW stockholders in the Merger.

Reduction of Dividends to be Received by CSW Stockholders

Based on the AEP current dividend of $2.40 per share and the Exchange Ratio, CSW's stockholders would receive $1.44 per share in dividends upon consummation of the Merger, which represents a reduction in the CSW stockholders' dividend payout ratio. On April 17, 1997, CSW announced its regular quarterly dividend on the CSW Shares of $0.435 per share, which represents an implied annual dividend rate of $1.74 per CSW Share and a dividend payout ratio of 91% of earnings per common share. The current CSW dividend payout ratio is significantly higher than the AEP dividend payment ratio. The historical dividend payout ratio per CSW Share for the year ended December 31, 1997 was 241.7%, compared to 88.7% per AEP Share. AEP does not anticipate making any changes to its dividend policy following the Merger; however, the AEP Board will continue to evaluate the financial condition and earnings of AEP and the appropriateness of its dividend policy. See "COMPARATIVE PER SHARE DATA".

Risks Related to the Business and Operations of AEP and CSW

Competitive and Regulatory Conditions

The Merger will combine two companies that share a common regulatory and competitive environment as well as a number of factors currently affecting certain electric utilities, including relatively high levels of debt and competition from municipal and other alternative providers of electric service. The electric utility industry has been undergoing dramatic structural change for several years, becoming increasingly competitive. This evolution is due to, among other things, the Energy Policy Act of 1992 and the issuance by FERC in 1996 of certain orders which have further opened the transmission systems of electric utilities to use by third parties. As a result of the Merger, these factors may affect the combined company to a greater degree than would be the case for either AEP or CSW on a stand-alone basis.

Environmental Risk Factors

AEP's and CSW's electric utility subsidiaries are subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters. It is expected that costs related to environmental requirements (including any changes in environmental statutes and regulations) will eventually be reflected in the rates of such subsidiaries. However, there can be no assurance that all environmental costs will be recovered. Certain proposed changes to federal air-quality control regulations and requirements could have adverse effects on AEP's and CSW's electric utility subsidiaries and on the post-Merger combined company. For example, the United States Environmental Protection Agency (the "USEPA") has recently revised ambient air quality standards for ozone and particulate matter. While those standards do not mandate emission levels for facilities such as electric generating plants, they may result in more areas being designated as non-attainment areas for those two pollutants, and states may be required to develop strategies to reduce such pollutants, including lowering emission levels for electric generating plants. With respect to ozone, the USEPA promulgated a new 8-hour standard of 80 parts per billion ozone in ambient air. The USEPA also issued state implementation plan deficiency notices to various states (including each of the states in which AEP's electric utility subsidiaries operate) calling for implementation of plans to reduce NO_x emissions consistent with the new 8-hour ozone standard, based mainly on a proposed reduction of power plant NO_x emissions to 0.15 lb./mmBtu (approximately 85% below 1990 levels). With respect to particulate matter emissions, the USEPA promulgated a new standard for fine particulate matter less than 2.5 microns in size. In addition, the USEPA intends to engage in studies, which may lead to regulation of mercury emissions by electric utilities in the future. Although the costs of meeting revised USEPA ambient air standards for ozone and particulate matter, along with other future environmental laws and regulations, cannot be precisely predicted at this time, such costs could be significant to AEP, and to lesser degree, CSW, as well as to the combined company.

THE AEP MEETING

This Joint Proxy Statement/Prospectus is first being mailed to shareholders of AEP on or about April 20, 1998 in connection with the solicitation of proxies by the AEP Board of Directors for use at the annual meeting of shareholders of AEP (the "AEP Meeting") to be held at The Ohio State University's Fawcett Center, 2400 Olentangy River Road, Columbus, Ohio on May 27, 1998, at 9:30 a.m., local time, and at any adjournment or postponement thereof.

Matters to be Considered

At the AEP Meeting, holders of AEP Shares will consider and vote upon proposals to (i) approve the issuance of AEP Shares in the Merger (the "Share Issuance"); (ii) approve an amendment to the Restated Certificate of Incorporation of AEP (the "AEP Charter") to increase the number of authorized AEP Shares from 300,000,000 to 600,000,000 (the "Charter Amendment"); (iii) elect 11 directors to the AEP Board of Directors (the "AEP Board"); (iv) ratify the appointment of Deloitte & Touche LLP as AEP's independent auditors for 1998 and (v) transact such other business as may properly come before the AEP Meeting or any adjournment(s) or postponement thereof.

The Board of Directors of AEP has by the unanimous vote of the directors present approved the Merger Agreement, the Merger and the other transactions contemplated thereby, and unanimously recommends a vote FOR the Share Issuance, FOR the Charter Amendment, FOR the proposed slate of AEP Directors and FOR the ratification of AEP's independent auditors.

Approval by the holders of AEP Shares of the Share Issuance is required by the NYSE because the number of AEP Shares to be issued in the Merger is expected to exceed 20% of the AEP Shares outstanding immediately prior to the Share Issuance.

The Charter Amendment increasing the number of authorized AEP Shares from 300,000,000 to 600,000,000 will enable AEP to have a sufficient number of shares for the Share Issuance. If the Merger is consummated, AEP estimates that up to 130,000,000 AEP Shares would be required for issuance in connection with the Merger (including the AEP Shares issuable upon exercise of CSW stock options outstanding at the Effective Time).

While AEP has no present intention of issuing any of the shares sought to be authorized that are not required to be issued in connection with the Merger, AEP believes that the availability of additional authorized shares would provide it with the ability to respond to future business needs and opportunities. The additional authorized shares would be available for issuance by AEP from time to time after the Effective Time without further action or authorization by shareholders (except as required by law or by a national securities exchange) in connection with possible investment opportunities, acquisitions of assets and other companies or for other corporate purposes as determined by the AEP Board. Such other corporate purposes might include raising additional capital funds through offerings of AEP Shares or of equity or debt securities convertible into or exchangeable for AEP Shares and the issuance of AEP Shares in connection with the employee benefit plans and executive compensation plans of AEP and its subsidiaries. If such additional authorized shares are issued to other than existing holders of AEP Shares, the percentage interest of such holders in AEP would be reduced. Although the existence or issuance of authorized but unissued shares of AEP capital stock could, under certain circumstances, have an anti-takeover effect, AEP has no present intention to issue such shares for anti-takeover purposes.

The Share Issuance will not be effected unless the Merger is consummated. The Charter Amendment will be effected, if approved by AEP shareholders, regardless of whether the Merger is consummated. Approval of both the Share Issuance and the Charter Amendment by the holders of AEP Shares are conditions to the consummation of the Merger.

At the AEP Meeting, holders of AEP Shares will also be asked to vote upon proposals for the election of the directors to the AEP Board, ratification of the appointment of Deloitte & Touche LLP as AEP's independent auditors for 1998 and such other business as may properly come before the AEP Meeting.

Record Date; Voting Rights; Required Vote; Confidential Voting

The holders of a majority in interest of the outstanding AEP Shares entitled to vote must be present in person or by proxy at the AEP Meeting in order for a quorum to be present. Only holders of record of AEP Shares at the close of business on April 8, 1998 (the "AEP Record Date"), will be entitled to receive notice of and to vote at the AEP Meeting. On the AEP Record Date, AEP had issued and outstanding 190,378,571 AEP Shares. As of the AEP Record Date, the AEP Shares were held by approximately 142,049 shareholders of record. Each AEP Share entitled to vote at the AEP Meeting entitles its holder to one vote, except with respect to the election of directors, for which voting is cumulative. Abstentions and broker non-votes (i.e shares held by brokers or nominees which are represented at a meeting but with respect to which the broker or nominee is not empowered to vote on a particular matter) will be counted as shares present for purposes of determining the presence or absence of a quorum at the AEP Meeting.

Approval of the Charter Amendment requires the affirmative vote of a majority of the outstanding AEP Shares. In determining whether this proposal has received the requisite number of affirmative votes, abstentions and shares which brokers do not have the authority to vote in the absence of timely instructions from the beneficial owners ("broker non-votes") will not be counted as votes cast and will have the same effect as a vote against the proposal. Abstentions may be specified with respect to approval of the Charter Amendment by properly marking the "ABSTAIN" box on the proxy for such proposal.

Approval of the Share Issuance requires the affirmative vote of a majority of the votes cast on the proposal, provided that the total votes cast on the proposal represent a majority of the outstanding AEP Shares entitled to vote thereon. Abstentions may be specified with respect to approval of the Share Issuance by properly marking the "ABSTAIN" box on the proxy for such proposal. For purposes of the

NYSE requirements, in determining (i) the total number of votes cast on such proposal and (ii) whether such proposal has been approved by a majority of the votes cast, abstentions will be counted and have the same effect as votes cast against the Share Issuance while broker non-votes will not be counted as votes cast.

In the election of directors, voting is cumulative. This means each AEP shareholder has the right to cast as many votes in the aggregate as equals the number of votes to which that shareholder is entitled (one vote for each AEP Share held) multiplied by eleven, the number of directors to be elected. Each AEP shareholder may cast the whole number of votes so computed for one candidate, or may distribute votes among the candidates, as the shareholder chooses. The proxies designated by the Board of Directors will not cumulate the votes of shares they represent. Directors will be elected by a plurality of votes cast by the holders of AEP Shares entitled to vote at the AEP Meeting. "Plurality" means that the individuals who receive the largest number of votes cast are elected as directors up to the maximum number of directors to be chosen at the meeting. An abstention may be specified with respect to voting for directors, by properly marking the "WITHHOLD" box on the proxy. Votes withheld with respect to one or more of the nominees and broker non-votes will not be counted as votes cast for such individuals and, accordingly, will have no effect on the outcome of the vote.

Ratification of the appointment of AEP's independent auditors requires the affirmative vote of a majority of the shares present in person or by proxy at the AEP Meeting and entitled to be voted. An abstention may be specified with respect to voting on such proposal, by properly marking the "ABSTAIN" box on the proxy for such proposal. In determining whether this proposal has received the requisite number of affirmative votes, abstentions and broker non-votes will not be counted as votes cast and, accordingly, will have no effect on the outcome of the vote.

This year, record holders of AEP Shares can also vote their shares by using a toll-free telephone number or the internet. Instructions for using these convenient new services are set forth on the enclosed proxy card.

Confidential Voting. It is the policy of AEP that shareholders be provided privacy in voting. All proxy (voting instruction) cards and ballots, which identify shareholders, are held confidential, except as may be necessary to meet any applicable legal requirements. Proxy cards are returned in envelopes addressed to an independent third-party tabulator, who receives, inspects, and tabulates the proxies. Voted proxies and ballots are not seen by nor reported to AEP except (i) in aggregate number or to determine if (rather than how) a shareholder has voted, (ii) in cases where shareholders write comments on their proxy cards, or (iii) in a contested proxy solicitation.

As of January 1, 1998, directors and executive officers of AEP and their affiliates were beneficial owners of an aggregate of 146,369 (less than 1%) of the outstanding AEP Shares.

Voting of Proxies

AEP Shares represented by all properly executed proxies received in time for the AEP Meeting will be voted at such meetings in the manner specified by the holders thereof. If no voting direction is indicated on the proxy card, the shares will be considered votes FOR the Charter Amendment, FOR the Share Issuance, FOR the election of the nominees for director (without cumulation) and FOR the appointment of Deloitte & Touche LLP as independent auditors for AEP for 1998. Proxy cards that are not signed or that are not returned are treated as not voted for any purpose. Proxies relating to "street name" shares that are voted by brokers will be counted as shares present for purposes of determining the presence of a quorum on all matters, but will not be treated as shares having voted at the AEP Meeting as to any proposal as to which authority to vote is withheld by the broker or with respect to which such broker or nominee is not empowered to vote.

It is not expected that any matter other than those referred to herein will be brought before the AEP Meeting. If, however, other matters are properly presented, the persons named as proxies will vote in accordance with their judgment with respect to such matters, unless authority to do so is withheld in the proxy.

Revocability of Proxies

The grant of a proxy on the enclosed AEP form of proxy does not preclude a shareholder from voting in person. An AEP shareholder may revoke a proxy at any time prior to its exercise by filing with the Secretary of AEP a duly executed revocation or proxy bearing a later date or by voting in person at the meeting. Attendance at the AEP Meeting will not of itself constitute a revocation of a proxy.

Solicitation of Proxies

Subject to the Merger Agreement, AEP and CSW each will bear the cost of its solicitation of proxies, except that AEP and CSW will share equally the cost of printing and mailing this Joint Proxy Statement/Prospectus. In addition to solicitation by mail, the directors, officers and employees of AEP and its subsidiaries may solicit proxies from shareholders of AEP by telephone or telegram or in person. Such directors, officers and employees will not be additionally compensated for such solicitation but may be reimbursed for out-of-pocket expenses in connection therewith. Arrangements will also be made with brokerage houses and other custodians, nominees and fiduciaries for the forwarding of solicitation material to the beneficial owners of shares held of record by such persons and AEP will reimburse such custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses in connection therewith.

Morrow & Co., Inc. will assist in the solicitation of proxies by AEP for a fee of $50,000, plus reasonable out-of-pocket expenses.

HOLDERS OF AEP SHARES SHOULD NOT SEND STOCK CERTIFICATES WITH THEIR PROXY CARDS. IF THE MERGER IS CONSUMMATED, HOLDERS OF AEP SHARES WILL NOT EXCHANGE SUCH SHARES OR RECEIVE ADDITIONAL AEP SHARES.

THE CSW MEETING

This Joint Proxy Statement/Prospectus is first being mailed to stockholders of CSW on or about April 20, 1998 in connection with the solicitation of proxies by the CSW Board of Directors (the "CSW Board") for use at the annual meeting of stockholders of CSW (the "CSW Meeting") to be held at the Dallas Museum of Art, 1717 North Harwood Street, Dallas, Texas, on May 28, 1998, at 10:30 a.m., local time, and at any adjournment or postponement thereof.

Matters To Be Considered

At the CSW Meeting, holders of CSW Shares, will consider and vote upon a proposal to approve and adopt the Merger Agreement and the transactions contemplated thereby, including the merger of a wholly-owned subsidiary of AEP with and into CSW as a result of which each outstanding CSW Share will be converted into the right to receive 0.60 of an AEP Share and CSW will become a wholly-owned subsidiary of AEP. **CSW's Board of Directors has determined that the terms of the Merger Agreement and the transactions contemplated thereby are fair to, and in the best interests of, CSW and its stockholders and recommends that CSW stockholders vote FOR the approval and adoption of the Merger Agreement.**

At the CSW Meeting, holders of CSW Shares will also be asked to (i) elect three members of the CSW Board of Directors to hold office as Class II directors until the CSW annual meeting in 2001, (ii) elect two members of the CSW Board of Directors to hold office as Class III directors until the CSW annual meeting in 1999 and (iii) ratify the appointment of Arthur Andersen, LLP as CSW's independent auditors for 1998. **The CSW Board of Directors has nominated E.R. Brooks, Robert W. Lawless and James L. Powell for election as Class II directors and William R. Howell and Richard L. Sandor for election as Class III directors. The CSW Board of Directors unanimously recommends that CSW stockholders vote FOR the election of such persons to the CSW Board of Directors and the ratification of Arthur Andersen LLP as CSW's independent auditors.**

The Board of Directors of CSW has approved the Merger Agreement, the Merger and the other transactions contemplated thereby, and recommends a vote FOR the approval and adoption of the Merger Agreement, FOR the proposed slate of directors and FOR the ratification of CSW's independent auditors.

Record Date; Voting Rights; Required Vote

The holders of a majority of the outstanding CSW Shares entitled to vote must be present in person or by proxy at the CSW Meeting in order for a quorum to be present. Only holders of record of CSW Shares at the close of business on April 8, 1998 (the "CSW Record Date"), will be entitled to receive notice of and to vote at the CSW Meeting. On the CSW Record Date, CSW had issued and outstanding 212,281,477 CSW Shares. As of the CSW Record Date, the CSW Shares were held by approximately 64,369 stockholders of record. Each CSW Share entitled to vote at the CSW Meeting entitles its holder to one vote. Abstentions and broker non-votes (i.e. shares held by brokers or nominees which are represented at a meeting but with respect to which the broker or nominee is not empowered to vote on a particular matter) will be counted as shares present for purposes of determining the presence or absence of a quorum at the CSW Meeting.

The affirmative vote of a majority of the outstanding CSW Shares entitled to vote thereon is required for approval and adoption of the Merger Agreement. Abstentions may be specified with respect to approval and adoption of the Merger by properly marking the "ABSTAIN" box on the proxy for such proposal. Abstentions and broker non-votes will have the effect of a vote against the approval and adoption of the Merger Agreement.

Directors will be elected by a plurality of votes cast by the holders of CSW Shares entitled to vote at the CSW Meeting. "Plurality" means that the individuals who receive the largest number of votes cast are elected as directors up to the maximum number of directors to be chosen at the meeting. Abstentions from voting for directors, by properly marking the "WITHHOLD" box on the proxy, as well as broker non-votes will be tabulated as votes withheld in the election of directors and will have no influence on the voting results.

Ratification of the appointment of CSW's independent public accountants or any other issue (other than election of directors and approval and adoption of the Merger) to be voted upon at the CSW Meeting requires the affirmative vote of a majority of the shares present in person or by proxy at the CSW Meeting and entitled to be voted. Abstentions will be counted as shares present and entitled to vote and therefore will have the same effect as a negative vote on whether ratification has been approved. Broker non-votes will have no influence on such voting results.

As of December 31, 1997, directors and executive officers of CSW and their affiliates were beneficial owners of an aggregate of 486,165 shares (less than 1%) of the outstanding CSW Shares.

Voting of Proxies

CSW Shares represented by all properly executed proxies received in time for the CSW Meeting will be voted at such meeting in the manner specified by the holders thereof. If no voting direction is indicated on the proxy card, the shares will be considered votes FOR the approval and adoption of the Merger Agreement, FOR the election of the nominees for director and FOR the appointment of Arthur Andersen LLP as independent auditors for CSW for 1998. Proxies relating to "street name" shares that are voted by brokers will be counted as shares present for purposes of determining the presence of a quorum on all matters, but will not be treated as shares having voted at the CSW Meeting as to any proposal as to which authority to vote is withheld or with respect to which a broker or nominee is not empowered to vote.

It is not expected that any matter other than those referred to herein will be brought before the CSW Meeting. If, however, other matters are properly presented, the persons named as proxies will vote in accordance with their judgment with respect to such matters, unless authority to do so is withheld in the proxy.

Revocability of Proxies

The grant of a proxy on the enclosed CSW form of proxy does not preclude a stockholder from voting in person. A CSW stockholder may revoke a proxy at any time prior to its exercise by filing with the Secretary of CSW a duly executed revocation of proxy or a proxy bearing a later date or by voting in person at the meeting. Attendance at the CSW Meeting will not of itself constitute a revocation of a proxy.

Appraisal Rights

No holders of CSW Shares will be entitled to appraisal rights under Delaware law if the Merger is approved. Under certain circumstances, the Delaware General Corporation Law (the "DGCL") entitles a shareholder to exercise its appraisal rights upon a merger or consolidation of the corporation effected pursuant to the DGCL if the holder complies with the requirements of Section 262 thereof. Appraisal rights are available under Section 262 of the DGCL if holders of shares in a constituent company to a merger, which shares are listed on a national securities exchange (as the CSW Shares are), are required by the terms of the merger to accept consideration other than shares of stock of the surviving corporation, shares of stock of any corporation listed on a national securities exchange, designated as a national market system security on an interdealer quotation system by the National Association of Securities Dealers, Inc. or held of record by more than 2,000 shareholders, or cash in lieu of fractional shares. As holders of CSW Shares will receive only AEP Shares, which are listed on the NYSE, and cash in lieu of fractional shares under the terms of the Merger Agreement, they are not entitled to appraisal rights under the DGCL.

Solicitation of Proxies

Subject to the Merger Agreement, AEP and CSW each will bear the cost of its solicitation of proxies, except that AEP and CSW will share equally the cost of printing and mailing this Joint Proxy Statement/ Prospectus. In addition to solicitation by mail, the directors, officers and employees of CSW and its subsidiaries may solicit proxies from stockholders of CSW by telephone or telegram or in person. Such directors, officers and employees will not be additionally compensated for such solicitation but may be reimbursed for out-of-pocket expenses in connection therewith. Arrangements will also be made with brokerage houses and other custodians, nominees and fiduciaries for the forwarding of solicitation material to the beneficial owners of shares held of record by such persons, and CSW will reimburse such custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses in connection therewith.

Innisfree M&A Incorporated will assist in the solicitation of proxies by CSW for a fee of $50,000, plus reasonable out-of-pocket expenses.

HOLDERS OF CSW SHARES SHOULD NOT SEND STOCK CERTIFICATES WITH THEIR PROXY CARDS. IF THE MERGER IS CONSUMMATED, CSW STOCKHOLDERS WILL BE FURNISHED INSTRUCTIONS FOR EXCHANGING THEIR CSW STOCK CERTIFICATES FOR AEP STOCK CERTIFICATES AT THAT TIME.

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THE COMPANIES

American Electric Power Company, Inc.

American Electric Power Company, Inc., a New York business corporation and the issuer of the AEP Shares covered by this Joint Proxy Statement/Prospectus, has its principal executive offices at 1 Riverside Plaza, Columbus, Ohio 43215-2373. Its telephone number is (614) 223-1000.

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company which owns all of the outstanding shares of common stock of seven domestic electric utility operating subsidiaries: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. In addition, in recent years AEP has been pursuing various unregulated business opportunities in the U.S. and worldwide.

The service area of AEP's electric utility subsidiaries covers portions of the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. The generating and transmission facilities of AEP's subsidiaries are physically interconnected, and their operations are coordinated, as a single integrated electric utility system. Transmission networks are interconnected with extensive distribution facilities in the territories served. The electric utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. As a result of the changing nature of the electric business, effective January 1, 1996, AEP's subsidiaries realigned into four functional business units: Power Generation; Nuclear Generation; Energy Delivery; and Corporate Development. In addition, the electric utility subsidiaries began to do business as "American Electric Power." The legal and financial structure of AEP and its subsidiaries, however, did not change.

In 1997, AEP and New Century Energies, Inc. jointly acquired Yorkshire Electricity Group plc ("Yorkshire Electricity"), through a holding company owned equally by each of AEP Resources, Inc. and New Century Energies, Inc. Yorkshire Electricity is an English independent regional electricity company, principally engaged in the distribution and supply of electricity to 2.1 million customers. In addition, a subsidiary of AEP Resources International, Limited has a 70% interest in Nanyang General Light Electric Co. Ltd., a joint venture in China organized to develop and build two 125 megawatt coal-fired generating units.

Central and South West Corporation

CSW, a Delaware corporation, has its principal executive offices at 1616 Woodall Rodgers Freeway, Dallas, Texas 75202-1234. Its telephone number is (214) 777-1000.

CSW is a Dallas-based public utility holding company registered under the 1935 Act. CSW owns all of the common stock of Central Power and Light Company ("CPL"), Public Service Company of Oklahoma ("PSO"), Southwestern Electric Power Company ("SWEPCO"), and West Texas Utilities Company ("WTU"), collectively, the "CSW U.S. Electric Operating Companies." CSW also owns all of the common stock of CSW Services, Inc., CSW Credit, Inc., CSW Energy, Inc., CSW International, Inc., CSW Communications, Inc., EnerShop Inc. and CSW Energy Services, Inc. and indirectly owns all of the outstanding share capital of SEEBOARD plc ("SEEBOARD"), a regional electric company in the United Kingdom. In addition, CSW owns 80% of the outstanding shares of common stock of CSW Leasing, Inc.

CSW U.S. Electric Operating Companies

The CSW U.S. Electric Operating Companies are public utility companies engaged in generating, purchasing, transmitting, distributing and selling electricity. The CSW U.S. Electric Operating Companies serve approximately 1.7 million customers in one of the largest combined service territories in the U.S.

covering approximately 152,000 square miles in portions of Texas, Oklahoma, Louisiana and Arkansas. The customer base of these companies includes a mix of residential, commercial and diversified industrial customers. CPL and WTU operate in portions of south and central west Texas, respectively. PSO operates in portions of eastern and southwestern Oklahoma, and SWEPCO operates in portions of northeastern Texas, northwestern Louisiana and western Arkansas.

CSW Services, Inc. performs, at cost, various accounting, engineering, tax, legal, financial, electronic data processing, centralized economic dispatching of electric power and other services for the CSW system, primarily for the U.S. Electric Operating Companies. During 1996, CSW functionally reorganized its domestic utility operations into three organizational units, power generation, energy delivery and energy services, which are centrally managed from CSW Services, Inc. The functional unbundling of CSW's vertically integrated structure is expected to provide a more competitive organizational structure. Certain employees were reassigned from the U.S. Electric Operating Companies to CSW Services, Inc. to provide these centrally managed services.

SEEBOARD

SEEBOARD is one of the 12 regional electricity companies in the United Kingdom. SEEBOARD's principal regulated businesses are the distribution and supply of electricity. In addition to its distribution and supply businesses, SEEBOARD is also engaged in other activities, including gas supply, electricity generation, electrical contracting and retailing.

SEEBOARD's service area covers approximately 3,000 square miles in Southeast England, extending from the outlying areas of London to the English Channel. The area has a population of approximately 4.6 million people with significant portions of the area, such as south London, having a high population density.

Other CSW Business Operations

CSW Energy, Inc. develops, owns and operates independent power and cogeneration facilities within the United States. CSW International, Inc. engages in international activities, including developing, acquiring, financing and owning exempt wholesale generators and foreign utility companies, either alone or with local or other partners.

CSW Communications, Inc. develops and operates telecommunications services primarily consisting of utility automation services and local telephone exchange services. EnerShop Inc. provides energy services to commercial, industrial, institutional and governmental customers.

CSW Credit, Inc. purchases, without recourse, accounts receivable from the CSW U.S. Electric Operating Companies and accounts receivable from certain non-affiliated parties, subject to limitations imposed under the 1935 Act. CSW Leasing, Inc. has investments in leveraged leases.

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THE MERGER

General

AEP, Sub and CSW have entered into the Merger Agreement which provides that, subject to the satisfaction or waiver of the conditions set forth therein (see "Conditions to the Consummation of the Merger"), Sub will be merged with and into CSW, CSW will be the surviving corporation in the Merger (the "Surviving Corporation") and each CSW Share will be converted into the right to receive 0.60 of an AEP Share together with cash in lieu of fractional AEP Shares. Contemporaneously with the closing under the Merger Agreement, a Certificate of Merger will be filed with the Secretary of State of the State of Delaware, and the Merger will become effective at the time of such filing unless otherwise provided in the Certificate of Merger.

The description of the Merger Agreement contained in this Joint Proxy Statement/Prospectus is qualified in its entirety by reference to the Merger Agreement, a copy of which is included as Annex I to this Joint Proxy Statement/Prospectus and is incorporated in its entirety herein by this reference.

Background of the Merger

General. AEP and CSW share a common vision of the future and are seeking to merge in furtherance of their shared strategy to become the nation's preeminent diversified electric utility. AEP and CSW share the view that the electric utility industry is in an era of accelerating change that will have a significant impact on the future competitive position of electric utility companies and their ability to maintain and increase earnings. Recently, the electric utility industry has begun a transformation that is being driven by technological advances, consumer pressures and federal and state legislative and regulatory initiatives aimed at introducing greater competition in the wholesale and retail energy markets. AEP and CSW each believe that efficient, low cost suppliers of energy with a diverse customer base will be best prepared to compete successfully in the rapidly changing electric energy marketplace.

Historically, competition in the wholesale and retail electric power markets was limited. In the wholesale market, this was due primarily to difficulties in obtaining transmission service over utility systems located between potential buyers and sellers and barriers to entry, including the threat of regulation under the 1935 Act. Pursuant to the Energy Policy Act of 1992 (the "Energy Act"), however, Congress authorized the FERC to exempt certain wholesale power sellers from regulation under the 1935 Act and, in 1996, the FERC issued Orders 888 and 889 under the Energy Act requiring utilities to provide non-discriminatory, open access transmission service upon request. These regulatory developments have resulted in an active competitive wholesale market for electricity. Although the retail market for electricity currently is considerably less competitive than the wholesale market, most states in which the utility subsidiaries of AEP and CSW provide retail service, have adopted or are actively considering legislative or regulatory action that has as its primary objective permitting retail customers to select their electricity supplier and obligating utilities to provide transmission and distribution service to competitors. As a result of these ongoing regulatory activities, the managements of AEP and CSW believe that there will soon be greatly increased competition in the retail sector of the business.

Both AEP and CSW believe that these changes are leading to a fundamental transformation of the electric utility business. They further believe that electric utility companies face increased business risks and opportunities and, unless they adapt quickly to the changing environment, will be limited in their ability to improve earnings. Many electric utilities are pursuing consolidation to reduce these risks and create new opportunities for earnings growth. Utilities confronting intensified competition have sought and, AEP and CSW believe, will continue to seek opportunities to create efficiencies and control costs through consolidation. AEP and CSW believe that strategic assets, such as a utility's transmission network and low cost generation assets, will be key factors in structuring the successful utility of the future and that customers in a competitive market will be particularly sensitive to an electric utility's efficiency and ability to respond to their needs.

For the past several years, AEP and CSW have separately been monitoring the changes occurring in the electric utility industry and focusing their strategic planning activities on adapting to an evolving competitive environment. These ongoing changes in the electric utility industry and strategic planning activities of AEP and CSW have led each of them to believe that a strategic merger of the two companies would be the best way to achieve their compatible long-term strategic goals.

Participants. Set forth below are the principal participants (and their offices and titles then held) in the discussions and negotiations that resulted in the Merger Agreement. At certain of the meetings described below under "Discussions" other employees or financial and legal advisers of AEP or CSW participated; however, the core members of the management and transaction teams involved in the discussions and negotiations are listed below.

AEP Management

E. Linn Draper, Jr.—Chairman of the Board, President and Chief Executive Officer
Donald M. Clements, Jr.—Executive Vice President, Corporate Development
Henry W. Fayne—Senior Vice President, Corporate Planning, Budgeting
Thomas S. Jobes—Managing Director, Corporate Development
Jeffrey D. Cross—Vice President & General Counsel, Corporate Development

CSW Management

E. R. Brooks—Chairman & Chief Executive Officer
Thomas V. Shockley III—President and Chief Operating Officer
Glenn Files—Executive Vice President
Ferd. C. Meyer, Jr.—Senior Vice President and General Counsel
Glenn D. Rosilier—Senior Vice President and Chief Financial Officer
Thomas M. Hagan—Senior Vice President, External Affairs
Venita McCellon-Allen—Senior Vice President, Corporate Development and Assistant Corporate Secretary
Michael D. Smith—President, Southwestern Electric Power Company
Stephen J. McDonnell—Vice President, Mergers and Acquisitions

Discussions. As indicated above, for the past several years, the management of CSW has been cognizant of the changing industry environment and engaged in a strategic planning process that was primarily focused on managing the corporation so that it would be poised to benefit from these changes.

In January 1997, senior management of CSW and AEP, including Mr. Brooks and Dr. Draper, began to discuss informally, as an adjunct to other discussions relating to potential international business opportunities, a potential merger of equals between AEP and CSW (implying a stock for stock exchange at current market prices without premium). On February 17, 1997, Dr. Draper and Mr. Clements met with Mr. Brooks and Mr. Shockley in Dallas to continue the discussions as to whether a merger of equals between AEP and CSW would be feasible. Following this meeting, Mr. Jobes and Mr. McDonnell were directed to explore the feasibility of a merger between the companies from a financial and regulatory point of view. To that end, in March 1997, AEP and CSW engaged joint advisers to consider regulatory issues. AEP and CSW also engaged a third party consultant to assist the senior managements of the two companies in an analysis of the cost savings and other synergies that might result therefrom. The joint advisers were asked to begin to study the feasibility of the potential merger. During March and April, AEP and CSW personnel met independently with the joint advisers to provide information; and Mr. Jobes and Mr. McDonnell spoke by telephone on several occasions to discuss the work of the joint advisers.

In March 1997, actions by the Texas Commission, including public comments in early March by one of the Commissioners and an order in late March by the Commission reducing rates of Central Power & Light Company, the largest utility of CSW, in a rate proceeding initiated in 1995 by CP&L, signaled the Texas electric utility industry that, in the absence of legislative action, the Texas Commission would not favor a full return on stranded investment during the transition to retail competition among Texas electric utilities. Legislation designed to deregulate the Texas electric utility industry, with the concomitant result of retail competition, was proposed in May 1997 but, despite the support of the Texas investor owned utilities, was not passed by the Texas legislature prior to the end of the legislative session in May 1997. In the opinion of CSW management, the indications of the Commission, combined with the uncertainty of such legislation passing, caused a substantial decline in the market price of CSW Shares during March 1997. On March 3, 1997, prior to the Commission actions mentioned above, the closing market price of the CSW Shares on the New York Stock Exchange was $24.00; in contrast, by April 17, 1997, the market price of the CSW Shares had declined to a closing sale price on that date of $18.25.

On April 17, 1997, CSW announced its regular quarterly dividend on the CSW Shares of $0.435 per share (an implied annual rate of $1.74 per CSW Share). At this level, the dividend payout ratio was 91% of earnings per common share. In announcing the dividend, CSW cautioned its stockholders that the CSW Board was continuing to monitor factors that could affect its dividend, that the recent rate order in the CP&L rate case, if ultimately upheld, would significantly affect CP&L's earnings and that the outcome of that case was one of many factors to be considered by the CSW Board as it reviews CSW's dividend policy.

Mr. Brooks notified Dr. Draper in late April that the decline in the market price of the CSW Shares rendered a merger of equals between AEP and CSW impracticable and as a result, CSW terminated the exploratory discussions with AEP regarding such a merger. They agreed, notwithstanding the termination of discussions, that AEP and CSW should receive the preliminary results of the work of the joint advisers. On April 25, 1997, teams led by Mr. Clements and Mr. Shockley met with the joint advisers in Columbus, Ohio to discuss the preliminary results of their work. Following consultation with the advisers of AEP and CSW, the representatives of the two companies were led to believe that a business combination of the two companies was feasible from a regulatory point of view.

The decline in the price of CSW Shares provided additional motivation to CSW management to explore its strategic alternatives, not only to position CSW to compete effectively in a changed industry environment, but also to restore shareholder value. As a consequence, CSW management accelerated its examination of its strategic alternatives.

In late April 1997, the chief executive officer of a large electric utility company ("Company A") requested Mr. Brooks to resume preliminary conversations about a possible business combination held earlier in the year. During May 1997, representatives of CSW met several times with management representatives of Company A to discuss the feasibility of a combination of the companies. These discussions also contemplated a merger of equals because the common stock of Company A was similarly depressed and therefore the market capitalization of the two companies were comparable. Pursuant to the provisions of a confidentiality agreement between the companies executed in May 1997, the two companies began the process of exchanging information necessary to determine the feasibility of a combination but did not engage in any discussions regarding the terms of any such combination. These discussions were, from CSW's point of view, tentative because CSW's management and Board of Directors had not at this time determined that a business combination was the preferred strategic alternative.

During May and June 1997, CSW management intensified its studies of certain other electric utility companies that had been identified as potential candidates for a strategic merger or business combination involving a stock for stock exchange. Another strategic alternative that was examined by management during this period was the feasibility of a divestiture of the transmission and distribution assets of CSW in order to concentrate on the domestic generation and power marketing businesses and the international electric power business (the "Asset Divestiture Plan"). In late July 1997, CSW engaged the Dallas office of

McKinsey & Co. ("McKinsey") to assist management in its evaluation of the Asset Divestiture Plan. At a meeting of the CSW Board of Directors on July 17, 1997, CSW management, together with Morgan Stanley & Co. Incorporated ("Morgan Stanley"), outlined for the directors potential strategic alternatives available to CSW to meet the changing industry environment and to restore and enhance long-term shareholder value, including possible business combinations and strategic alliances with other companies, the Asset Divestiture Plan and other options that could be pursued on a stand along basis. No specific companies, other than AEP and Company A, were identified at this meeting as being possible business combination candidates.

During late July and August 1997, CSW management, with the assistance of its advisers, including McKinsey and Morgan Stanley, continued to evaluate the Asset Divestiture Plan and the process of screening potential business combination candidates.

As indicated above, CSW management believes that strategic assets, such as a utility's transmission network and low cost generation, will be key factors in structuring the successful utility of the future and that premiums will be placed on efficiency and the ability to respond to the needs of customers. CSW management further believes that efficient, low cost suppliers of energy with a diverse customer base will be best prepared to compete successfully in the rapidly changing electric energy marketplace. Accordingly, the screening criteria for potential business combination candidates required that any candidate be of sufficient size to permit the efficient production of low cost energy and that the candidate have a management strategy focused on reducing or diversifying exposure to regulatory risks, reducing exposure to stranded investment, establishing a significant electric power trading capability, building a national retail and wholesale presence and pursuing growth in selected international investments. In addition, the screening criteria required that a business combination with any candidate be feasible from a regulatory point of view. During this period, CSW management concluded that a stock for stock business combination with a candidate meeting the screening criteria that involved a premium over the market price of the CSW Shares was preferable to a merger of equals with a company whose common stock was similarly depressed.

In August and early September 1997, Mr. Brooks held three meetings with the chief executive officer of Company A and during those meetings discussed CSW's progress in evaluating its strategic alternatives. McKinsey began to assist CSW in its process of screening potential strategic business combination candidates. During early September 1997, Mr. Brooks, based on a careful examination of the aforementioned strategic alternatives and intensive study of potential business combination candidates and information developed by CSW management from that process, met with Dr. Draper to determine AEP's interest in renewing discussions regarding a potential business combination and with the chief executive officers of two other large electric utility companies ("Company B" and "Company C") to determine their interest, if any, in exploring a possible business combination with CSW. All expressed strong interest in engaging in preliminary discussions with CSW.

The Board of Directors of CSW met again on September 10, 1997 and discussed the progress of CSW management in its ongoing evaluation of potential strategic alternatives. Subsequently, CSW representatives met with representatives of two other large electric utility companies. Neither of those companies was then in a position to enter into discussions regarding a possible business combination.

At a meeting of the Board of Directors on September 27, 1997, CSW management and McKinsey discussed with the CSW Board their views on the changing conditions in the electric utility industry generally and, more specifically, in Texas and the impact of such changing conditions on CSW and its business and prospects. They also discussed the challenges facing and opportunities available to CSW under each of the several strategic alternatives that had been under study and previously discussed by CSW's management with the CSW Board, including a possible business combination and strategic alternatives that could be pursued by CSW on a stand-alone basis, and how each of these strategic alternatives might affect CSW and long-term stockholder value. CSW management and the CSW Board discussed extensively the impact of the electric utility industry restructuring, the best means to enhance

CSW's capabilities in fuel contracting, power sales, trading and asset acquisitions and CSW's ability to build a national retail presence. At this point, CSW management advised the directors that management, after extensive study, had determined not to recommend the Asset Divestiture Plan and explained the reasons for this determination, which included risks associated with potential adverse federal income tax consequences, CSW's ability to sell its transmission and distribution assets for a fair price given regulatory uncertainty in Texas, its ability successfully to apply the proceeds of any such sale to the acquisition of additional generation capacity and the barriers to entry and already significant competition in the electric power trading market. Morgan Stanley then presented a financial analysis of CSW's strategic alternatives, including a business combination analysis and an analysis of the stand-alone alternatives. In conclusion, Mr. Brooks informed the CSW Board of CSW management's belief that CSW's strategic vision should include reducing or diversifying exposure to regulatory risks, reducing its exposure to stranded investment, establishing a significant electric power trading capability, building a national retail and wholesale presence and pursuing focused growth in international investments, and that implementation of this strategy would be the best way to restore and enhance long-term stockholder value. CSW management then recommended to the CSW Board that CSW seek a strategic combination with a partner that could enhance CSW's ability to implement its strategic vision. CSW management further recommended that any strategic combination candidate should have a comparable strategic vision with that of CSW in order to maximize the likelihood that the combination would bring the most long-term value to CSW's stockholders. In the view of CSW management, such a merger candidate should own generation capacity that would be competitive in a deregulated environment, have a national presence with a solid reputation in the electric utility industry and not increase CSW's exposure to stranded costs. Mr. Brooks also informed the CSW Board that he had been in contact with the chief executive officers of certain potential strategic combination candidates that, in the view of CSW management, met these criteria and that several of them were interested in discussing a merger. At the conclusion of CSW management's presentation, the CSW Board unanimously authorized CSW management to pursue discussions with companies that had been identified to the CSW Board as having the potential to contribute to the realization of CSW's long-term strategy while continuing to evaluate CSW's stand-alone options.

While CSW management had earlier conveyed to AEP, Company B and Company C the notion that CSW would not entertain any business combination proposal that did not, in addition to meeting the screening criteria, include a significant premium to the CSW Shares market price, in late September 1997 Mr. Brooks conveyed the same notion to the chief executive officer of Company A. The latter responded by advising Mr. Brooks that Company A was not in a position to consider such a premium, and the discussions with Company A were, accordingly, suspended.

In early October 1997, Mr. Brooks met with the chief executive officer of a smaller electric utility company at the request of the latter. During the meeting, the latter expressed strong interest in pursuing a business combination transaction between CSW and his company. Mr. Brooks informed the chief executive officer that, in the views of CSW management, the combination was not an appropriate strategic fit and that his company did not meet CSW's screening criteria.

On October 8 and 15, 1997, CSW management conferred by telephone with the CSW Board regarding the progress made by CSW management in its discussions with potential business combination candidates. During these calls, CSW management identified for the CSW Board several candidates that had indicated an interest in pursuing exploratory discussions with CSW about a strategic merger.

Messrs. Brooks, Shockley and Rosilier met with Dr. Draper on October 9, 1997 in Columbus, Ohio. This discussion concerned the parties' interest in a potential strategic combination and the need to expand their exploratory discussions to include a larger group of employees and advisers.

In mid-October 1997, the Chief Executive Officer of Company A called Mr. Brooks to ask if Company A could resume talks with CSW concerning a potential merger with a significant premium to the CSW Shares market price, if a large component of the consideration to CSW stockholders would be cash. Mr.

Brooks informed him that such a proposal would not be responsive to CSW's interest in a potential stock-for-stock transaction if CSW chose not to remain independent, but that CSW would give due consideration to any such proposal from Company A and evaluate it in light of CSW's other strategic alternatives.

During October 1997, CSW executed confidentiality agreements with AEP, Company B and Company C and commenced the exchange of nonpublic information. During this period, McKinsey completed its review of the electric utility industry and confirmed management's list of potential business combination candidates. Mr. Brooks also approached the chief executive officer of one other electric utility company on CSW's list of candidates regarding his company's interest in a potential business combination. That chief executive officer indicated interest but determined not to engage in business combination discussions because of perceived regulatory concerns.

On October 23, 1997, CSW management, consultants and financial and legal advisers met with the CSW Board in the corporate offices of CSW to discuss further the strategic alternatives available to CSW, including a possible strategic merger and strategic alternatives that could be pursued by CSW on a stand-alone basis. CSW management, consultants and advisers discussed with the CSW Board the rationale behind CSW management's recommendation that a strategic combination be considered and reviewed the overall progress of CSW management's efforts to identify the best strategic merger partner, as measured against the criteria previously outlined by Mr. Brooks to the CSW Board. CSW management and McKinsey compared and contrasted the option of remaining independent with a strategic combination, discussing in particular the need to build skills for a deregulated market and the desirability of having sufficient size and a large, diverse customer base to support and expand those skills. CSW management and McKinsey also discussed with the CSW Board the process of identifying the best strategic combination partner, the status of the process at that time and each of the candidates then being evaluated by CSW management. As regards each potential business combination candidate, CSW management reported specifically with respect to its then developed views regarding the likelihood of regulatory approval of such a business combination. Morgan Stanley reviewed for the CSW Board the earnings analysis for CSW on a stand-alone basis presented at the September 27 meeting, discussed the financial condition of several strategic merger candidates and presented an accretion/dilution analysis with respect to a strategic merger with each. CSW management also discussed with the CSW Board the contacts made with potential candidates. At the conclusion of the meeting, the CSW Board authorized management to continue the screening process and ratified the execution of confidentiality agreements with selected candidates.

On October 29, 1997, in a telephone conference, the initial transaction teams of AEP and CSW organized a mutual evaluation process. Mr. Jobes and Mr. McDonnell initiated the telephone conference which resulted in the decision to renew their efforts to identify and quantify the potential cost savings and synergies resulting from such a business combination with the assistance of a third party consultant.

On October 30, 1997, Mr. Brooks and other senior executives of AEP and CSW met at a hotel in Columbus, Ohio to make initial presentations about the business, operations, financial condition and prospects of their respective companies.

On October 31, 1997, Mr. Brooks and other executives met with executives of Company B in Dallas to explore the possibility of a strategic business combination and the issues raised thereby, and Mr. Brooks and other executives met with executives of Company A in Dallas for the same purpose.

On November 4, 1997, Mr. Shockley and other executives met with executives of Company C in Dallas to discuss the possibility of a strategic business combination and related issues.

On November 5, 1997, CSW management met with the CSW Board by telephone conference to update the CSW Board on the process of identifying the best strategic partner. Mr. Brooks reviewed for the CSW Board the status of the discussions with AEP and the other potential strategic merger candidates. On November 6 and 7, 1997, members of the transaction teams of CSW and AEP held meetings at the offices of Salomon Brothers Inc., now doing businesss as Salomon Smith Barney ("Salomon Smith

Barney") in Chicago, Illinois to discuss regulatory and financial matters relating to a potential merger. The regulatory discussions included presentations by legal advisers to AEP and CSW with respect to the regulatory filing and approval processes that would be required in order to consummate a merger. Presentations were made with respect to the required filings with and findings or approvals by the FERC, SEC, NRC, U.S. Justice Department and Federal Trade Commission and each of the states in which AEP and CSW operate. The discussions also concerned the potential regulatory issues that might arise, and the potential regulatory filings that might be necessary, in connection with the Merger as a result of the two companies' respective operations in the United Kingdom. The discussion of financial matters consisted primarily of explanations of the financial information previously exchanged by AEP and Salomon Smith Barney with CSW and Morgan Stanley.

By letter dated November 6, 1997, the chief executive officer of Company A advised Mr. Brooks that, while previous discussions had involved the possibility of a merger of equals, Company A was now willing to discuss a stock and cash transaction involving a 15 to 20 percent premium to the CSW Shares market price on such date. On November 11, 1997, the chief operating officer of Company A forwarded to Mr. Brooks a copy of a report (the "Company A McKinsey Report") rendered by another office of McKinsey & Company that compared a business combination of CSW with AEP, Company A and Company C and concluded that the combination with Company A was the most favorable, based on large part on Company A's assessment of the likelihood of regulatory approval of each such transaction.

During the first two weeks of November, CSW established transaction teams consisting of officers of CSW and representatives of its financial and legal advisers to meet with their counterparts at AEP and Companies A, B and C to exchange information and to evaluate further the desirability and feasibility of a strategic business combination with each. Each of these companies was informed by CSW that it was engaged in a process of evaluating its strategic alternatives and that it was engaged in discussions with other unidentified companies. During this period, the CSW transaction teams met with their counterparts at each of the four strategic business combination candidates numerous times for the purpose of exchanging information and evaluating the issues relating to a potential business combination.

On November 13 and 14, 1997, CSW management and CSW's advisers met with the CSW Board in Austin, Texas to discuss further the strategic alternatives available to CSW, including a possible strategic merger as well as various stand-alone alternatives. CSW management reported to the CSW Board the receipt of the Company A McKinsey Report and that CSW management had sought and received assurance from McKinsey that no information regarding CSW was shared by the Dallas office with personnel in the other office of McKinsey & Company. CSW management and CSW's consultants and advisers discussed with the CSW Board the rationale behind CSW management's recommendation that a strategic merger be considered and reviewed the overall progress of CSW management's efforts to identify the optimal strategic merger partner as measured against the criteria previously discussed with the CSW Board. CSW management discussed with the CSW Board the status of the discussions with AEP and the other potential strategic merger candidates and the regulatory filing and approval process that would be required in connection with a strategic combination and how that process would differ as applied to a merger with each candidate. CSW management and Morgan Stanley also discussed with the CSW Board the business, operations, financial condition and prospects of the candidates and their relative strengths and weaknesses. especially the compatibility of each candidate's strategic plan with CSW's plan and the extent to which they satisfied the criteria previously outlined to the CSW Board.

At this meeting, the CSW Board authorized the formation of the Corporate Strategy Review Committee (the "CSW Committee") to facilitate greater involvement and direction by the CSW Board in the evaluation process. The CSW Committee consisted of Messrs. Donald M. Carlton, Joe H. Foy, William R. Howell, Robert W. Lawless and James L. Powell. Mr. Foy, was appointed Chairman of the CSW Committee. The CSW Board directed the CSW Committee (i) to keep fully informed, on behalf of the CSW Board, regarding the progress of evaluation of the strategic alternatives available to CSW, including the possibility of a strategic combination or of remaining independent, (ii) to participate in the direction of such process, (iii) to evaluate any proposals received by CSW pursuant to such process or otherwise, (iv) to determine which, if any, proposal is in the best long-term interests of CSW and its stockholders, (v) to ensure that it is kept informed of, and to direct, the negotiation of the terms and conditions of any combination contemplated by any proposal and (vi) to recommend to the CSW Board any such combination that the CSW Committee shall determine to be in the best long-term interests of CSW and its stockholders.

From November 15 through November 24, 1997, CSW management and advisers continued their discussions with all the potential strategic merger candidates. On November 20 and 21, members of the transaction teams of CSW and AEP met at the offices of Salomon Smith Barney in Chicago, Illinois to continue exploratory due diligence and to discuss regulatory issues. At these meetings the two teams answered due diligence questions and continued their earlier discussions of the regulatory approval process.

On November 24, 1997, CSW management and CSW's advisers met with the CSW Committee in the corporate offices of CSW to inform the CSW Committee on the progress of the strategic alternative evaluation process. The CSW Committee received a thorough briefing on the ongoing discussions that were continuing with AEP and the other potential strategic merger candidates. To bring closure to the evaluation process, the CSW Committee authorized CSW management to send to each of the four strategic merger candidates a letter (the "Request Letters") requesting each of the candidates to advise CSW formally as to whether it was interested in pursuing a strategic combination with CSW. In the Request Letters, CSW asked each recipient to advise CSW as to the principal terms and conditions under which it was prepared to discuss such a business combination. The Request Letters also advised the recipients regarding the minimum essential parameters of a business combination proposal required by CSW in order to receive full consideration by CSW, including the parameter that any combination should be structured as a tax free, stock-for-stock transaction.

From November 25 through December 11, 1997, CSW management and advisors continued exploratory discussions with each of the strategic merger candidates. On December 2, 1997, members of the transaction teams of AEP and CSW met in Washington, D.C. to review certain regulatory and other issues.

On December 5, 1997, the CSW Committee met by telephone conference. CSW management and advisers briefed the CSW Committee on the ongoing discussions with the potential strategic merger candidates held since November 24, 1997. CSW management reviewed with the CSW Committee the process that resulted in the discussions with AEP and the other candidates, and discussed its views of the financial and operational strengths of each potential strategic merger candidate and the perceived business prospects of each combination. During these discussions, CSW management emphasized the factors discussed at previous CSW Board and CSW Committee meetings in presenting an analysis of each of the potential strategic merger candidates. Morgan Stanley also informed the CSW Committee of its discussions with the financial advisers to each of the candidates (other than Company C which had not engaged a financial adviser).

On December 5, 1997, the CSW Board met with CSW management and CSW's financial advisers to receive an update on the status of CSW's efforts to identify a potential strategic combination partner. The CSW Committee reported to the CSW Board on the CSW Committee's meetings held November 14, 1997, November 24, 1997 and December 5, 1997. The report contained a review of the deliberations of the CSW Committee during these meetings, including a briefing with respect to the Request Letters, the rationale therefor and the content thereof. During this meeting, Mr. Brooks outlined and discussed all of the issues being considered by the CSW Committee, CSW management and CSW's financial advisers with respect to each of the candidates. CSW management also updated the CSW Board with respect to the status of discussions with AEP and Company A, Company B and Company C. Morgan Stanley also informed the Board about conversations it had with the financial advisers to each of AEP and Company A and Company B.

On December 6, 1997, the AEP Board met with AEP management and AEP's legal and financial advisors to consider submitting a preliminary indication of interest with respect to a possible business combination with CSW in response to the Request Letter. At the meeting, AEP management and the financial and legal advisors of AEP advised the AEP Board as to the status of the due diligence review of CSW's business, operations and financial condition conducted to date and feasibility of consummating the proposed business combination.

On December 11, 1997, CSW received affirmative responses to the Request Letters from AEP, Company A and Company B. Company C declined to respond citing anticipated regulatory and accounting concerns. AEP's response indicated that, based on the information it had received to date and subject to satisfactory completion of due diligence, AEP would be interested in continuing discussions with CSW that could lead to a merger pursuant to which each CSW Share would be exchanged for .58 of one AEP Share (an implied value of $28.60 per CSW Share based on the closing sale price of the AEP Shares on December 10, 1997). The response from Company A indicated that company would be interested in discussing a business combination in which 60% of the CSW Common Stock would be converted into cash at $29 per share and the balance would be converted into common stock of a new entity having a market value of $29 per share of CSW Common Stock based on a trading period prior to closing. The response from Company B indicated that it would, based on and subject to further analysis of several significant assumptions relating to forecasted financial results and other matters, be interested in discussing a business combination in which the CSW Common Stock would be converted into common stock of Company B having a market value of $26 to $28 per share of CSW Common Stock.

CSW management deemed the proposal from Company A to be nonresponsive to the Request Letter primarily because the large cash component of the merger consideration was inconsistent with the objective of the CSW management and CSW Board that the CSW shareholders be afforded the opportunity to participate in the company resulting from any strategic merger pursued by CSW, and CSW management so advised the Committee at its meeting on December 12, 1997.

After receipt of the response from Company B, Mr. Brooks called the chief executive officer of Company B to advise him that the implied value of his proposal would need to be higher than $28 per CSW Share in order to be considered seriously by CSW. The response of the latter was that he could only improve his offer if substantial risks were removed from the transaction, some of which were beyond the control of CSW.

On December 12, 1997, CSW management and advisers met with the CSW Committee at the corporate offices of CSW to discuss affirmative responses and the status of the strategic merger candidate evaluation process. CSW management and legal advisers discussed with the CSW Committee the content of each of the responses received and compared each of them to the terms and conditions requested by CSW in the Request Letters. Each response was also discussed in the context of the discussions being conducted with that strategic merger candidate and the evaluations of the candidates presented at prior CSW Board and CSW Committee meetings. CSW management also reviewed for the CSW Committee the strengths and weaknesses of each responding candidate and how compatible each of their business plans was with CSW's strategic vision. Morgan Stanley reviewed with the CSW Committee the key financial terms of each proposal and noted the valuation of AEP's proposal based on the respective stock prices as of December 11, 1997 was higher than the other two proposals. The CSW Committee then discussed the stand-alone options available to CSW and compared those to the potential strategic mergers under consideration. After further discussion, the CSW Committee determined that AEP appeared to be the best strategic merger partner for CSW and that a merger with AEP on the right terms would be more likely to restore and enhance long-term stockholder value than any of the other merger or stand-alone strategic alternatives. The CSW Committee then requested CSW management to seek a more favorable exchange ratio. The CSW Committee authorized CSW management to proceed to negotiation of a definitive business combination agreement with AEP if CSW management was successful in improving the exchange ratio.

On December 12, 1997, in accordance with instructions from the CSW Committee, Mr. Brooks called Dr. Draper to inform him that CSW management was prepared to recommend that CSW enter into negotiations with AEP in an effort to reach agreement on a merger if AEP would increase the suggested exchange ratio. Following negotiations between Dr. Draper and Mr. Brooks regarding various exchange ratios throughout the day, Dr. Draper agreed to increase the proposed exchange ratio to .60 of one AEP Share for each CSW Share (an implied value of $29.74 per CSW Share based on the closing sale price of AEP Shares on December 12, 1997). Later in the day, Mr. Brooks informed Dr. Draper that CSW management was authorized by the CSW Committee to proceed with merger negotiations on that basis.

From December 13 through December 17, 1997, both CSW and AEP accelerated their due diligence efforts, with both companies' teams working primarily in data rooms established at the offices of CSW's legal counsel in Dallas, Texas. On December 16, 1997, CSW delivered a draft merger agreement to AEP. Numerous small group meetings were held to discuss the regulatory approval process, environmental matters, nuclear operations and other matters, with the results of such meetings reported to AEP and CSW managements.

On December 17, 18 and 19, 1997, the CSW Committee met by telephone conference with CSW management and advisers and the committee's counsel to discuss the status of the negotiations with AEP. CSW management discussed with the CSW Committee the due diligence efforts being conducted by both companies and the progress of the merger negotiations.

On December 17, 1997, the AEP Board met with AEP management and AEP's legal and financial advisors to review the status of the negotiations with CSW. AEP management advised the AEP Board with respect to the due diligence efforts being conducted by both companies and the progress of the Merger negotiations. Representatives of Salomon Smith Barney made a presentation to the AEP Board with respect to certain analyses preformed by Salomon Smith Barney in evaluating the consideration proposed to be paid by AEP in connection with the Merger.

From December 18 through December 20, 1997, negotiating teams from AEP and CSW met at the offices of AEP's legal counsel in New York, New York to negotiate the terms of the Merger Agreement.

On December 20, 1997, the CSW Committee met at the corporate offices of CSW in Dallas, Texas. At this meeting, CSW management updated the CSW Committee on the progress of the negotiations with AEP and discussed with the CSW Committee a number of other issues. CSW management presented a report to the CSW Committee regarding the strategic fit of a merger with AEP as compared with other possible merger candidates or stand-alone options available to CSW and how the various alternatives would affect stockholder value. Legal counsel discussed with the CSW Committee the substantive issues involved in obtaining FERC approval of a merger with AEP and compared those issues and their likely resolution with the issues raised by a combination with the other responding candidates. Legal counsel also discussed the regulatory environment in several of the states in which AEP operates. Mr. Hagan discussed regulatory issues in the States of Arkansas, Louisiana, Oklahoma and Texas as they relate to a merger with AEP and the other potential strategic merger candidates. Mr. Meyer reviewed for the CSW Committee the 1935 Act requirements that would apply to a merger with AEP and the other potential strategic merger candidates and also reviewed the feasibility of the proposed merger under the various applicable regulatory requirements. Mr. Files discussed with the CSW Committee certain environmental issues associated with a merger with AEP. Mr. Files reviewed for the CSW Committee the environmental due diligence undertaken by CSW and its environmental advisers, in particular with respect to AEP's coal mining operations and its coal-fired generation plants. Mr. Files discussed the impact of possible legislation on AEP's operations and the likely costs associated therewith. Mr. Smith reported to the CSW Committee on the expected cost savings and other synergies that would result from a merger with AEP and how these cost savings and other efficiencies might be realized and reflected in the combined company's future operations. Mr. Rosilier discussed the accounting and tax treatment of a merger with AEP. Morgan Stanley presented a detailed financial analysis of the proposed merger, including valuations for each of CSW and

AEP on a stand-alone and combined basis utilizing certain stated assumptions regarding cost efficiencies and enhanced revenues. Morgan Stanley's report included historical and comparative price earnings ratios, historical market prices and the relationships of such prices to general market performance. Morgan Stanley also informed the CSW Committee that Morgan Stanley would issue an opinion to the CSW Board that the exchange ratio in the Merger was fair to CSW's common stockholders from a financial point of view. See "The Merger—Opinion of Financial Adviser to CSW". Mr. Shockley reviewed significant issues in the Merger agreement. He reported on the proposed methods of resolving operational issues between the companies pending consummation of the Merger. He also outlined the terms and conditions of various material adverse events which could result in either party terminating the Merger Agreement. CSW's outside counsel reviewed the substantive provisions of the Merger Agreement, including the termination and termination fee provisions. At the conclusion of the meeting, the CSW Committee voted unanimously to recommend to the CSW Board that it authorize CSW to enter into the Merger on the terms and conditions outlined and discussed thoroughly during the presentations to the CSW Committee.

On December 21, 1997, at a special meeting of the CSW Board held in the corporate offices of CSW, Mr. Foy presented the CSW Committee's report and recommendation to the CSW Board and Mr. Foy and Mr. Brooks reviewed for the CSW Board those issues discussed at the December 20, 1997 CSW Committee meeting. CSW's outside counsel reviewed with the CSW Board the terms of the final forms of the Merger Agreement and other transaction documents. Counsel also reviewed the approval process to be commenced upon execution of the Merger Agreement, including the process of seeking approval of AEP and CSW stockholders and the various regulatory agencies whose approval would be required. Mr. Meyer discussed with the CSW Board various provisions of the 1935 Act and their applicability to the proposed Merger and to the operations of the combined entity after the effective time of the proposed Merger. He also reviewed with the CSW Board the feasibility of the proposed merger under the various applicable regulatory requirements. Morgan Stanley delivered its oral opinion to the CSW Board to the effect that, as of such date and based upon and subject to various considerations, the proposed exchange ratio of .60 of one of the AEP Shares for each CSW Share was fair, from a financial point of view, to the holders of CSW Shares. The CSW Board then reviewed the presentations they had received at this and previous CSW Board meetings concerning CSW's strategic alternatives and how best to restore and enhance long-term stockholder value, discussing and considering, among other things: current industry, economic and market conditions; the effects of the changing regulatory environment and increased competition on CSW's earning potential as a stand-alone company; the results of due diligence on AEP and its operations and business prospects; the impact of current and anticipated environmental legislation on the combined company; expected cost savings and synergies resulting from the Merger that will enhance opportunities for earnings growth and create value for stockholders; diversification and, hence, reduction of regulatory risks that would result from the Merger; creation of a larger service territory with a more diversified customer base, thereby reducing the adverse impact of regional economic downturns; increased flexibility and leverage in financing; creation of a larger low-cost generating system allowing for a reduction in reserve margins and deferring the need to add generating capacity; enhanced ability to make off-systems sales; the tax and accounting treatment of the Merger; the regulatory feasibility of the Merger; and increased opportunities in wholesale and retail energy marketing. Upon conclusion, the CSW Board unanimously approved an amendment of the Stockholder Rights Plan to exempt the Merger from the application thereof and, by a vote of twelve in favor and one against, approved the Merger Agreement and the transactions contemplated thereby. Mr. Glenn Biggs was the sole director to vote against approval of the Merger Agreement and the transactions contemplated thereby based on his expressed beliefs that the Merger Agreement should contain a collar limiting the effect of any potential decline in the market price of the AEP Shares prior to consummation of the Merger and that, despite legal advice to the contrary, the Merger might not be feasible under the 1935 Act. See "THE CSW MEETING—ADDITIONAL MATTERS—Election of Directors" and "—Meetings and Compensation of the CSW Board."

On December 21, 1997, the AEP Board met to consider the proposed Merger. Representatives of AEP's senior management, AEP's legal advisors and its financial advisors made presentations and reviewed the matters set forth under "Reasons for the Merger." The terms of the proposed Merger and the provisions contained in the draft of the Merger Agreement were reviewed with the AEP Board. Salomon Smith Barney rendered its oral opinion, confirmed by a subsequent written opinion dated December 21, 1997, that, as of such date, and based upon and subject to the considerations set forth therein, the consideration to be paid by AEP in connection with the Merger was fair to AEP from a financial point of view. After discussion and consideration, the AEP Board approved the Merger, the Merger Agreement and all of the related transactions with the unanimous vote of all directors present (Ms. Kathryn D. Sullivan being absent from the meeting).

Following the meetings of the AEP Board and the CSW Board, the Merger Agreement was executed.

Reasons for the Merger

AEP and CSW share a common vision of the strategic path necessary to succeed in the increasingly competitive utility and energy services marketplace. The electric utility industry has been undergoing dramatic structural change for several years. This evolution has been marked by the Energy Policy Act of 1992 and the issuance by the FERC in 1996 of Orders 888 and 889 which further opened the transmission systems of electric utilities to use by third parties. To compete more effectively in the dynamic and increasingly competitive global energy and related services market, AEP and CSW believe that companies must be able to market and deliver a wide variety of energy services across various energy forms at competitive prices. Both AEP and CSW foresee a convergence of energy-related services, electric utility services and potentially other utility services such as telecommunications.

AEP and CSW believe that the Merger will position the combined companies to be the nation's preeminent diversified electric utility company, and that the Merger offers significant opportunities to create additional value for shareholders, customers and employees of AEP and CSW. The benefits of the Merger include the following:

- **Increased Scale**—The combined company will be a substantially larger enterprise than either AEP or CSW on a stand-alone basis. As competition intensifies within the industry, AEP and CSW believe scale will be one contributor to overall business success. Scale has importance in many areas, including utility operations, product development, advertising and corporate services. The Merger is expected to improve the profitability of the combined company by roughly doubling the customer base and providing synergies in all of these areas.

- **Cost Savings**—Through the elimination of duplication in corporate and administrative programs, greater efficiencies in operations and business processes, improved purchasing power, and the combination of two workforces, the companies expect to capture Merger-related savings of approximately $2 billion, net of transaction and transition costs, over the next ten years, based on preliminary estimates by the managements of AEP and CSW. These estimated cost savings would be attributable to the Merger and would not include other types of savings that might be achieved without a business combination of AEP and CSW. The estimated cost savings reflect the creation of cost reduction or cost avoidance opportunities through the ability to consolidate separate, stand-alone operations into a single entity.

- **Competitive Prices and Services**—Sales to industrial, large commercial and wholesale customers are at greatest near-term risk as a result of increased competition in the electric utility industry. It is expected that the Merger will create a company better able to meet the demands of such customers for reliable, low-cost power in the face of increased competition among suppliers and will create operating efficiencies that will allow the combined companies to be able to produce and deliver low-cost power to customers.

- **Financial Strength**—By significantly increasing the market capitalization of the combined company compared with the individual companies, it is expected that the Merger will result in a combined company with a stronger financial base, improved position in the credit markets and less exposure to regional economic downturns.

- **Greater Diversification**—The combination of the two companies will immediately increase the companies' ability to serve a larger and more diverse base of customers. The combined service territories of AEP and CSW will be more diverse than their individual service territories, reducing exposure to adverse changes in any sector's economic and competitive conditions. After the Merger, the combined company plans to expand relationships with existing customers and to develop relationships with new customers in its service area, using its combined distribution channels to market a portfolio of innovative energy-related products throughout the region at competitive prices. In addition to geographic diversity, the Merger will result in a combined company which has greater diversity in fuel and generation, which its expected to reduce dependence upon any one sector of the energy industry and reduce exposure to fluctuations in certain commodity prices.

Subject to the qualifications expressed below, AEP and CSW believe that the Merger will generate substantial cost savings to the combined company following the Effective Time, which would not be available absent the Merger. As mentioned above, preliminary estimates by the management of AEP and CSW indicate that the Merger could result in potential net non-fuel cost savings (that is, after taking into account the costs incurred to achieve such savings) of approximately $2.0 billion during the ten-year period following the Merger. Potentially significant cost savings include personnel reductions and reduced corporate and administrative programs. Assuming a March 31, 1999 closing, AEP and CSW estimate available synergies and cost savings resulting from the Merger, net of costs necessary to achieve these reductions, of approximately $17 million (9 months), $102 million, $135 million, $162 million, $181 million. $243 million, $255 million, $259 million. $267 million, $275 million and $69 million (3 months) in the first ten years following the Merger, respectively, for a total of approximately $2 billion. The synergies and the cost savings in the first five years are expected to be lower than the later years due to the costs incurred to achieve certain synergies and cost savings. The categories and estimated amounts of non-production cost synergies and cost savings over the ten year period are anticipated to be as follows: labor savings of approximately $996 million, corporate and administrative savings of approximately $1,044 million. and purchasing economy savings of approximately $367 million. Achievement of these savings will require incurring an estimated cost of $248 million and does not include estimated savings from pre-merger initiatives of approximately $193 million. The companies are required to obtain state regulatory approvals of the Merger in the states of Texas. Oklahoma, Louisiana and Arkansas as well as from the FERC. the NRC, the FCC and the SEC. In addition, the companies must await the expiration or termination of the applicable waiting period under the HSR Act. As part of the filings, the companies plan to propose regulatory plans which suggest an equitable sharing of the net savings from the Merger which will be requested to be amortized over a multi-year period. Although specific estimates of the net savings to the shareholders cannot be determined until all regulatory proceedings have been completed, it is expected that approximately half of the net savings would be realized by the shareholders. In addition. it is anticipated that there will be reduced fuel costs.

The analyses employed by the managements of AEP and CSW in order to develop estimates of potential savings as a result of the Merger were necessarily based upon various assumptions. The estimated merger cost savings are assumed to be available coincident with closing at or about March 31, 1999 and to extend over a ten-year period concluding March 31, 2009. The material assumptions include savings that are provided in nominal dollars based on escalation rates of approximately 3% for all non-labor areas and 4% for salaries and wages. These escalation rates are also adjusted for other areas where price changes differ from general escalation rates. No assumptions are made with respect to individual company cost reductions; rather, reductions are assumed to occur across both companies using blended cost rates. Reductions in staffing levels are assumed to occur across both companies and reflect the areas where overlap or duplication are expected. Cost reductions in other non-labor areas reflect either duplication in expenditures, for example information technology, or economies of scale in purchasing services, such as insurance. These avoided duplicate expenditures reflect specific projects, where identifiable, or assumed project cost levels based on the plans of the individual companies. Economies of scale are predicated upon perceived opportunities to reduce unit costs based on observed prices paid and the results of expected negotiations. Accordingly, while AEP and CSW believe that such assumptions are reasonable for purposes of the development of estimates of potential savings, there can be no assurance that such assumptions will approximate actual experience or that such savings will be realized. See "Summary of the Joint Proxy Statement/Prospectus—Cautionary Statement Concerning Forward-Looking Statements." The nature of the allocation of the estimated cost savings resulting from the Merger will depend in part upon the results of regulatory proceedings in the various jurisdictions in which AEP and CSW operate their utility businesses. See "Regulatory Approvals."

In the past, such regulatory commissions have occasionally required a particular allocation of estimated merger-related cost savings as a condition of approval of a merger. If a commission requires that some part of merger-related cost savings be allocated to customers, those savings will necessarily be unavailable to the stockholders of the combined company. However, the Merger Agreement provides that consummation of the Merger is dependent on regulatory approvals that do not impose terms, conditions, or qualifications that, individually, or in the aggregate, could resonably be expected to have a Material Adverse Effect on the combined company.

Recommendations of the Boards of Directors

AEP. THE AEP BOARD HAS BY THE UNANIMOUS VOTE OF THE DIRECTORS PRESENT AT THE MEETING APPROVED THE MERGER AGREEMENT AND DETERMINED TO RECOMMEND THE CHARTER AMENDMENT AND THE SHARE ISSUANCE. THE AEP BOARD RECOMMENDS THAT THE HOLDERS OF AEP COMMON STOCK VOTE FOR APPROVAL OF THE CHARTER AMENDMENT AND THE SHARE ISSUANCE.

The determination of the AEP Board to approve the Merger and the transactions contemplated thereby was based upon consideration of a number of factors. The following list includes the material factors considered by the AEP Board in its evaluation of the Merger and the transactions contemplated thereby: (i) AEP's and CSW's respective businesses, operations, assets, management, geographic locations and prospects; (ii) current industry, economic, market and regulatory conditions and trends which encourage consolidation to create new business strategies and earnings growth; (iii) potential opportunities for enhanced value for customers arising out of the operating efficiencies of the combined company due to the combined company's stronger competitive position; (iv) AEP's and CSW's strategic fit and compatible corporate cultures and visions of the future of the energy business; (v) the financial resources of the combined company; (vi) the ability to consummate the Merger, including, in particular, the ability to obtain required regulatory approvals on a timely basis without the imposition of conditions that could reasonably be expected to have a material adverse effect on the combined company; (vii) the anticipated positive effects of the Merger on long-term value for shareholders through their ownership of stock in a stronger, more diversified company; (viii) the geographically attractive service territory of CSW expanding the breadth and diversity of markets for the combined company to service; (ix) the diversification of AEP's and CSW's fuel and environmental risks; (x) the terms of the Merger Agreement, which provide for reciprocal representations and warranties, conditions to closing and rights to termination (as discussed under "The Merger Agreement"); (xi) the recent incidence of Merger transactions involving electric utility companies in surrounding markets, which is part of a wider trend in the utility industry towards consolidation and strategic partnerships in order to create larger, stronger companies made to face an increasingly competitive environment; (xii) the impact of regulation under various state and federal laws, in particular the federal and state legislative and regulatory initiatives aimed at introducing greater competition in the wholesale and retail energy markets, and the feasibility of obtaining regulatory approvals required as conditions to the consummation of the merger; and (xiii) the opinion of Salomon Smith Barney that, as of December 21, 1997 and based upon and subject to the considerations set forth therein, the consideration to be paid by AEP in the Merger was fair to AEP from a financial point of view, which opinion was confirmed as of the date of this Joint Proxy Statement/Prospectus. In view of the variety of factors considered in connection with its evaluation of the Merger, the AEP Board of Directors did not find it practicable to and did not quantify or otherwise assign relative weights to the specific factors considered in reaching its determination. In making its determination, the AEP Board of Directors also considered the risks and likelihood of achieving the results discussed above.

CSW. CSW'S BOARD OF DIRECTORS HAS DETERMINED THAT THE TERMS OF THE MERGER AGREEMENT AND THE TRANSACTIONS CONTEMPLATED THEREBY ARE FAIR TO, AND IN THE BEST INTERESTS OF, CSW AND ITS STOCKHOLDERS AND RECOMMENDS THAT CSW STOCKHOLDERS VOTE FOR THE APPROVAL OF THE MERGER AGREEMENT.

In considering the recommendation of the CSW Board with respect to the Merger Agreement, stockholders should be aware that certain members of the CSW Board will become directors and/or employees of AEP following consummation of the Merger and/or may become entitled to severance benefits as a result of the Merger. Therefore, such directors have interests in the Merger that are different than, or in addition to, the interests of stockholders of CSW generally. The CSW Board was aware of these interests and considered them, among other matters, in approving the Merger Agreement. See "—Interest of Certain Persons in the Merger."

The Board of Directors of CSW believes that the terms of the Merger Agreement are fair to, and that the Merger is in the best interests of, CSW and its stockholders. Accordingly, the Board of Directors of CSW has approved the Merger upon the terms and conditions contained in the Merger Agreement and recommends approval and adoption thereof by the stockholders of CSW.

In engaging in the process of screening and evaluating potential strategic merger candidates and in reaching its determination to approve and recommend the Merger Agreement, the CSW Board was motivated in its desire to position CSW to meet the challenges of the changing electric utility industry environment discussed under "—Background of the Merger" and thereby to assist the holders of CSW Shares to realize the benefits of the opportunities, and to avoid the risks, presented by such changing environment. In addition, the CSW Board was motivated to restore stockholder value lost as a result of the events in March and April 1997 as described under "—Background of the Merger."

In its deliberations with respect to the Merger and the Merger Agreement, the CSW Board consulted with CSW management and the financial and legal advisers to CSW. The factors considered by the CSW Board include those enumerated below. While all of these factors were considered by the CSW Board, the CSW Board did not make determinations with respect to each such factor. *Rather, the CSW Board made its judgment with respect to the Merger and the Merger Agreement based on the total mix of information available to it, and the judgments of individual directors may have been influenced to a greater or lesser degree by their individual views with respect to different factors.*

The factors considered by the CSW Board in evaluating the Merger and the Merger Agreement included the following:

(i) its knowledge of the business, operations, assets, properties, operating results and financial condition of CSW;

(ii) CSW's strategic alternatives, including the prospects of positioning CSW for the future and restoring and enhancing long-term shareholder value by remaining an independent company or by effecting a strategic business combination with another party;

(iii) information concerning CSW's prospects as an independent company, including financial projections for the year ended December 31, 1999;

(iv) information concerning the financial position, results of operations, businesses, competitive position and prospects of a business combination with each of AEP, Company A and Company B, including the amount of stranded investment of each;

(v) the philosophies of the managements of each of AEP, Company A and Company B, especially as they relate to the means of meeting the challenges of industry change, and the compatibility of those with that of CSW management;

(vi) the prospects of regulatory approval, at each level of regulation, of a combination with each of AEP, Company A and Company B;

(vii) the opportunities for cost savings as a result of a business combination with each of AEP, Company A and Company B (which, in the case of AEP, were estimated by the managements of AEP and CSW to be approximately $2.0 billion to be realized over the ten years following the consummation of the Merger);

(viii) the extensive information developed during the period of the screening process discussed under "—Background of the Merger" with respect to AEP, Company A and Company B, as well as the extensive and inclusive nature of the screening process itself;

(ix) the comparative market capitalization, debt-to-equity ratio and financial strength of each of CSW as an independent company and a combination of CSW with each of AEP, Company A and Company B;

(x) the effects of the changing regulatory environment and increased competition in the electric power industry as described under "—Background of the Merger";

(xi) the positive effects of the Merger on CSW's customers through a positioning of CSW to achieve the most reliable and low-cost power production and delivery;

(xii) the recent trend in the utility industry toward consolidation and strategic partnerships that create larger, stronger companies made to face an increasingly competitive environment;

(xiii) specifically, with respect to a business combination with AEP:

(a) the Exchange Ratio and recent trading prices for CSW Shares and AEP Shares;

(b) the opportunity for the stockholders of CSW to receive a premium over the market price for their CSW Shares immediately prior to announcement of the Merger Agreement (the Exchange Ratio implied a premium of $5.20, or 20%, over the closing market price per CSW Share on December 19, 1997 based on the closing market price ($52.00) for AEP Shares on the same day);

(c) the anticipated positive effects of the Merger on CSW stockholders through their ownership of stock in a combined company that will likely have greater stability and strength due to its geographically expanded service territory having a more diversified customer base, thereby reducing the adverse impact of regional economic downturns and reducing regulatory risks, its increased economies of scale, its expected cost savings and synergies expected to result from the consolidation of CSW's and AEP's stand-alone operations, its larger low-cost generating system allowing for a reduction in reserve margins and deferring the need to add generating capacity, its enhanced ability to make off-systems sales, its increased opportunities in wholesale and retail energy marketing, and its expected increased flexibility and leverage in financing activities;

(d) the terms of the Merger Agreement, which provide for reciprocal representations and warranties, conditions to closing and rights to termination, balanced rights and obligations and protection for employees of CSW (as discussed under "The Merger Agreement");

(e) the tax and accounting treatment of the Merger; and

(f) the numerous presentations made by Morgan Stanley to the CSW Board during the screening process, including information regarding CSW as an independent entity and CSW in combination with AEP, Company A and Company B (as well as others) and the oral opinion of

Morgan Stanley rendered to the CSW Board on December 21, 1997 that, as of such date, the Exchange Ratio was fair, from a financial point of view, to the holders of the CSW Shares. See "—Opinion of Financial Adviser to CSW".

During its deliberations regarding the Merger and the Merger Agreement (and, indeed, during the screening process), the CSW Board also analyzed certain risks associated with the Merger. First, it was drawn to the CSW Board's attention that a business combination with AEP would likely involve a reduction in the dividend enjoyed by holders of CSW Shares. Based on the AEP current dividend rate of $2.40 per share and the Exchange Ratio, CSW's stockholders would receive $1.44 per share in dividend upon consummation of the Merger. Second, the CSW Board was advised with respect to the environmental risks faced by AEP. Specifically, these entail the risk of more restrictive clean air legislation and consequent capital expenditure requirements to meet clean air standards at AEP's coal fired plants. Third, the CSW Board was thoroughly advised regarding the risks of obtaining regulatory approval for the Merger at all levels of regulation. After reviewing these matters thoroughly, including the relatively high CSW dividend payout ratio in comparison with the industry average, the extensive due diligence investigation by CSW representatives of the AEP environmental risks and the legal advice received by CSW with respect to regulatory approvals, the CSW Board determined that the benefits of the Merger outweighed any risks entailed in these matters.

The CSW Board believes that the Merger will provide strategic and operational opportunities that would be unavailable to CSW as an independent company and will enable CSW and its stockholders to participate in a significantly larger and more diverse company. Through the pooling of common stock equity, management, human resources and technical expertise and coordination in the use of the facilities of CSW and AEP, the CSW Board believes the combined company will be better able to meet the competitive environment for the delivery of energy and services than would CSW as a stand-alone enterprise. The CSW Board believes that the combined entity will be better able, in the long term, to achieve benefits of increased financial stability and strength, improved and unified management, efficiencies of operations, better use of facilities for the benefit of customers and reduced or deferred requirements for future additional generating capacity than would CSW as an independent company or a combination of CSW with Company A or Company B.

In view of the wide variety of factors considered by it in connection with its evaluation of the Merger and the Merger Agreement, the CSW Board did not find it practicable to quantify or otherwise to attempt to assign relative weights to the specific factors considered in reaching its determination and did not do so. Rather, the CSW Board made its judgment with respect to the Merger and the Merger Agreement based on the total mix of information available to it, and the judgments of individual directors may have been influenced to a greater or lesser degree by their individual views with respect to different factors. In making its determination, the CSW Board of Directors also considered the risks and likelihood of achieving the results discussed above.

Opinion of Financial Advisor to AEP

AEP retained Salomon Smith Barney, pursuant to a letter agreement dated September 3, 1997 (the "Salomon Engagement Letter") to act as financial advisor to AEP in connection with a potential merger with CSW. Pursuant to the Salomon Engagement Letter, Salomon Smith Barney rendered an opinion to the AEP Board on December 21, 1997 to the effect that, based upon and subject to the considerations set forth in such opinion, as of such date, the consideration to be paid by AEP in the Merger was fair to AEP from a financial point of view. Salomon Smith Barney has confirmed its opinion dated December 21, 1997 by delivery of a written opinion dated the date of this Joint Proxy Statement/Prospectus. In connection with its opinion dated the date of this Joint Proxy Statement/Prospectus, Salomon Smith Barney updated certain of the analyses performed in connection with its opinion delivered on December 21, 1997 and reviewed the assumptions on which such analyses were based and the factors considered in connection therewith.

The full text of Salomon Smith Barney's opinion dated the date of this Joint Proxy Statement/ Prospectus (the "Salomon Smith Barney Opinion"), which sets forth the assumptions made, general procedures followed, matters considered and limits on the review undertaken, is included as Annex II to this Joint Proxy Statement/Prospectus. The summary of Salomon Smith Barney's opinion set forth below is qualified in its entirety by reference to the full text of such opinion. No limitations were imposed by AEP or AEP's Board of Directors with respect to the investigations made or procedures followed by Salomon Smith Barney in rendering its opinions. **Shareholders are urged to read the Salomon Smith Barney Opinion in its entirety.**

In connection with rendering its opinion, Salomon Smith Barney reviewed and analyzed, among other things, the following: (1) the Merger Agreement; (2) certain publicly available information concerning AEP, including the Annual Reports on Form 10-K of AEP for each of the years in the four year period ended December 31, 1997 and the Quarterly Reports on Form 10-Q of AEP for the quarters ended March 31, June 30, and September 30, 1997; (3) certain other internal information, primarily financial in nature, including projections, concerning the business and operations of AEP furnished to Salomon Smith Barney by AEP for purposes of its analysis; (4) certain publicly available information concerning the trading of, and the trading market for, the AEP Shares; (5) certain publicly available information concerning CSW, including the Annual Reports on Form 10-K of CSW for each of the years in the four year period ended December 31, 1997 and the Quarterly Reports on Form 10-Q of CSW for the quarters ended March 31, June 30, and September 30, 1997; (6) certain other internal information, primarily financial in nature, including projections, concerning the business and operations of CSW furnished to Salomon Smith Barney by CSW for purposes of its analysis; (7) certain publicly available information concerning the trading of, and the trading market for, the CSW Shares; (8) certain internal information concerning the prospects of the combined operations of AEP and CSW furnished to Salomon Smith Barney by AEP for purposes of its analysis; (9) certain publicly available information with respect to certain other companies that Salomon Smith Barney believed to be comparable to CSW or AEP, and the trading markets for certain of such other companies' securities; and (10) certain publicly available information concerning the nature and terms of certain other transactions that Salomon Smith Barney considered relevant to its inquiry. Salomon Smith Barney also considered such other information, financial studies, analyses, investigations and financial, economic and market criteria that it deemed relevant. Salomon Smith Barney also met with certain officers and employees of AEP and CSW to discuss the foregoing as well as other matters Salomon Smith Barney believed relevant to its inquiry.

In its review and analysis and in arriving at its opinion, Salomon Smith Barney assumed and relied upon the accuracy and completeness of all of the financial and other information provided to it or publicly available and neither attempted independently to verify nor assumed any responsibility for verifying any of such information. Salomon Smith Barney did not conduct a physical inspection of any of the properties or facilities of AEP or CSW, nor did it make or obtain or assume any responsibility for making or obtaining any independent evaluations or appraisals of any of such properties or facilities. With respect to projections, Salomon Smith Barney assumed that they had been reasonably prepared on bases reflecting the best currently available estimates and judgments of the managements of AEP and CSW as to the future financial performance of AEP and CSW, respectively. Salomon Smith Barney expressed no view with respect to such projections or the assumptions on which they were based. Salomon Smith Barney further assumed that the conditions precedent to the Merger contained in the Merger Agreement will be satisfied and that the Merger will be consummated in accordance with the terms of the Merger Agreement.

In conducting its analysis and arriving at its opinion, Salomon Smith Barney considered such financial and other factors as it deemed appropriate under the circumstances including, among others, the following: (1) the historical and current financial position and results of operations of CSW and AEP; (2) the business prospects of CSW and AEP; (3) the historical and current market for the AEP Shares, the CSW Shares and the equity securities of certain other companies that Salomon Smith Barney believed to be comparable to AEP or CSW; and (4) the nature and terms of certain other acquisition transactions that

Salomon Smith Barney believed to be relevant. Salomon Smith Barney also took into account its assessment of general economic, market and financial conditions as well as its experience in connection with similar transactions and securities valuation generally. Salomon Smith Barney's opinion necessarily was based on conditions as they existed and could be evaluated on the date thereof and Salomon Smith Barney assumed no responsibility to update or revise its opinion based upon circumstances or events occurring after such date. Salomon Smith Barney's opinion does not constitute an opinion or imply any conclusions as to the likely trading range for the AEP Shares following consummation of the Merger. Salomon Smith Barney's opinion was for the benefit of AEP's Board of Directors and management in their consideration of the Merger and was, in any event, limited to the fairness, from a financial point of view, of the consideration to be paid by AEP in the Merger and did not address AEP's underlying business decision to effect the Merger or constitute a recommendation of the Merger to AEP or a recommendation to any holder of AEP Shares or CSW Shares as to how such holder should vote with respect to the Merger.

In connection with rendering its opinion on December 21, 1997, Salomon Smith Barney made a presentation to the AEP Board on December 17, 1997, with respect to certain analyses performed by Salomon Smith Barney in evaluating the consideration to be paid by AEP in connection with the Merger. The following is a summary of such Salomon Smith Barney presentation. The following quantitative information, to the extent it is based on market data, is based on market data as it existed at December 15, 1997 and is not necessarily indicative of current market conditions.

Discounted Cash Flow Analyses—CSW. Salomon Smith Barney performed a discounted cash flow ("DCF") analysis, based on financial projections provided by CSW and adjusted by the management of AEP, to establish a range of equity value per share for the CSW Shares. The DCF was calculated for CSW assuming discount rates ranging from 7.75% to 8.50% and was comprised of the sum of the present value of (i) the projected unlevered free cash flows for fiscal years 1997 to 2006 and (ii) the fiscal year 2006 terminal value based upon a range of multiples from 13.5x to 14.5x projected net income for fiscal year 2006. From this analysis, Salomon Smith Barney derived a range of the implied equity value per CSW Share of approximately $25.00 to $29.00. Salomon Smith Barney also calculated the present value, net after-tax, of the approximately $2.0 billion in pre-tax synergies (estimated in an analysis prepared by management of AEP and CSW with the assistance of a third-party consultant to be achieved over the next approximately 10 years). Salomon Smith Barney derived a present value of those synergies of approximately $5.00 per CSW share. Based on the foregoing, Salomon Smith Barney derived a reference range for the implied value per CSW share, including synergies, of approximately $30.00 to $34.00.

Comparable Company Analysis—CSW. Salomon Smith Barney reviewed certain publicly available financial, operating and stock market information for CSW, and five other publicly-traded utility companies (Dominion Resources, Inc., GPU, Inc., Houston Industries Incorporated, PP&L Resources, Inc. and Texas Utilities Company (the "CSW Comparable Companies")). Salomon Smith Barney considered the CSW Comparable Companies to be reasonably similar to CSW insofar as they participate in business segments similar to the CSW's business segments, but none of these companies has the same management, makeup, size and combination of businesses as CSW. Accordingly, the analysis described below is not purely mathematical. Rather it involves complex considerations and judgments concerning differences in historical and projected financial and operating characteristics of CSW and the CSW Comparable Companies and other factors that could affect public trading value.

For CSW and each of the CSW Comparable Companies, Salomon Smith Barney compared the ratio of market equity value as of December 15, 1997 to (1) latest twelve months ("LTM") net income (13.3x for CSW compared with a range of 11.0x to 17.2x for the CSW Comparable Companies); (2) 1997 estimated net income (16.2x for CSW compared with a range of 10.9x to 13.6x for the CSW Comparable Companies); (3) 1998 estimated net income (13.3x for CSW compared with a range of 10.9x to 13.0x for the CSW Comparable Companies); (4) book value (1.54x for CSW compared with a range of 1.35x to 1.52x for the CSW Comparable Companies); (5) LTM after-tax cash flow (5.8x for CSW compared with a range of 4.6x to 6.0x for the CSW Comparable Companies); (6) 1997 estimated after-tax cash flow (5.6x for CSW compared with a range of 4.6x to 5.7x for the CSW Comparable Companies); and (7) 1998 estimated after-tax cash flow (6.5x for CSW compared with a range of 4.6x to 5.7x for the CSW Comparable Companies). Salomon Smith Barney also compared the ratio of firm value (calculated as the offer value plus total debt, preferred equity and minority interests less cash) as of December 15, 1997 to (1) LTM earnings before interest, taxes, depreciation and amortization ("EBITDA") (7.9x for CSW compared with a range of 6.0x to 8.5x for the CSW Comparable Companies); (2) 1997 estimated EBITDA (7.5x for CSW compared with a range of 5.6x to 7.3x for the CSW Comparable Companies); and (3) 1998 estimated EBITDA (6.9x for CSW compared with a range of 5.6x to 7.2x for the CSW Comparable Companies). Using the multiples described above, Salomon Smith Barney derived reference ranges for the implied value of the CSW Shares (1) on a stand-alone basis ($21.00 to $25.00 per share); (2) including approximately $5.00 per share for the present value of the net after-tax synergies expected to result from the Merger ($26.00 to $30.00 per share); and (3) including a 30% control premium, but no synergies ($27.50 to $32.50 per share).

Analysis of Selected Utility Company Mergers and Acquisitions. Salomon Smith Barney also analyzed certain publicly available financial, operating and stock market information for seven selected merger or acquisition transactions in the utility industry announced since August 1996 (the "Precedent Utility Transactions"). The Precedent Utility Transactions reviewed were LG&E Energy Corp./KU Energy Corporation, Enron Corp./Portland General Corp., Allegheny Power System, Inc./DQE Inc., Western Resources Inc./Kansas City Power & Light Co., Brooklyn Union Gas Co./Long Island Lighting Co., WPL Holdings, Inc./IES Industries, Inc., and WPL Holdings, Inc./Interstate Power Co. Salomon Smith Barney considered the Precedent Utility Transactions to be reasonably similar to the Merger, but none of these precedents is identical to the Merger. For each transaction reviewed, Salomon Smith Barney established, among other things, the premium to market price one month prior to the public announcement of the transaction and the multiples of (1) offer price to trailing twelve months earnings per share (ranging from 13.0x to 17.5x); (2) offer price to forward earnings per share (ranging from 14.0x to 18.0x); (3) offer price to forward plus one year earnings per share (ranging from 14.0x to 17.5x); (4) offer price to book value (ranging from 1.5x to 2.1x); (5) firm value to LTM EBITDA (ranging from 6.8x to 8.5x); and (6) firm value to LTM earnings before interest and taxes ("EBIT")(ranging from 10.0x to 13.0x). The premium of offer price to market price in the Precedent Utility Transactions (excluding WPL Holdings, Inc./Interstate Power Co., based on Salomon Smith Barney's judgment that the process that led to that transaction was not sufficiently comparable to the process resulting in the Merger) ranged from 17.0% to 36.0% with a median of 30.0% and a mean of 29.0%. From this analysis, Salomon Smith Barney derived a reference range for the implied equity value per CSW Share of $27 to $35.

An analysis of the results of the foregoing necessarily involves complex considerations and judgments concerning differences in financial and operating characteristics of CSW and other factors that would affect the acquisition value of the companies to which it is being compared. Mathematical analysis (such as determining the mean or median) is not, in itself, a meaningful method of using precedent transactions data.

Discounted Cash Flow Analysis—AEP. Salomon Smith Barney performed a DCF analysis, based on financial projections provided by management of AEP, to establish a range of equity value per share for the AEP Shares. The DCF was calculated for AEP assuming discount rates ranging from 7.75% to 8.50% and was comprised of the sum of the present value of (i) the projected unlevered free cash flows for fiscal years 1997 to 2006 and (ii) the fiscal year 2006 terminal value based upon a range of multiples from 13.5x to 14.5x projected net income for fiscal year 2006. From this analysis, Salomon Smith Barney derived a reference range of the implied equity value per AEP Share of approximately $42.00 to $49.00.

Comparable Company Analysis—AEP. Salomon Smith Barney reviewed certain publicly available financial, operating and stock market information for AEP, and six other publicly-traded utility companies (Allegheny Power System, Inc., CINergy Corp., Dominion Resources, Inc., New Century Energies, Inc., Northern States Power Co., and The Southern Company (the "AEP Comparable Companies")). Salomon

Smith Barney considered the AEP Comparable Companies to be reasonably similar to AEP insofar as they participate in business segments similar to AEP's business segments, but none of these companies has the same management, makeup, size and combination of businesses as AEP. Accordingly, the analysis described below is not purely mathematical. Rather it involves complex considerations and judgments concerning differences in historical and projected financial and operating characteristics of AEP and the AEP Comparable Companies and other factors that could affect public trading value.

For AEP and each of the AEP Comparable Companies, Salomon Smith Barney compared the ratio of market equity value as of December 15, 1997 to (1) to LTM net income (15.2x for AEP compared with a range of 13.6x to 17.7x for the AEP Comparable Companies); (2) 1997 estimated net income (15.1x for AEP compared with a range of 13.1x to 15.9x for the AEP Comparable Companies); (3) 1998 estimated net income (15.1x for AEP compared with a range of 12.6x to 14.6x for the AEP Comparable Companies); (4) book value (2.06x for AEP compared with a range of 1.49x to 2.36x for the AEP Comparable Companies); (5) LTM after-tax cash flow (8.1x for AEP compared with a range of 5.1x to 8.1x for the AEP Comparable Companies); (6) 1997 estimated after-tax cash flow (7.8x for AEP compared with a range of 5.1 x to 8.2x for the AEP Comparable Companies); and (7) 1998 estimated after-tax cash flow (7.8x for AEP compared with a range of 5.0x to 7.7x for the AEP Comparable Companies). Salomon Smith Barney also compared the ratio of firm value as of December 15, 1997 to (1) LTM EBITDA (8.0x for AEP compared with a range of 7.5x to 9.1x for the AEP Comparable Companies); (2) 1997 estimated EBITDA (8.0x for AEP compared with a range of 6.7x to 9.5x for the AEP Comparable Companies); and (3) 1998 estimated EBITDA (7.8x for AEP compared with a range of 6.6x to 9.1x for the AEP Comparable Companies). Using the multiples described above, Salomon Smith Barney derived a reference range for the implied value of the AEP Shares of $44.00 to $52.00.

Historical Trading Ratios Analysis. Salomon Smith Barney also reviewed the daily closing prices of the CSW Shares and the AEP Shares during the period from December 15, 1992 through December 15, 1997 and the implied historical trading ratios determined by dividing the price per CSW Share by the price per AEP Share (the "Historical Trading Ratio") over such period. Salomon Smith Barney calculated that during that period the Historical Trading Ratio ranged from a high of 0.91 to a low of 0.44 with an average of 0.70. Over the one-month period preceding December 15, 1997, the Historical Trading Ratio ranged from a high of 0.52 to a low of 0.45 with an average of 0.49. Over the six-month period preceding December 15, 1997, the Historical Trading Ratio ranged from a high of 0.52 to a low of 0.44 with an average of 0.47. Over the one-year period preceding December 15, 1997, the Historical Trading Ratio ranged from a high of 0.65 to a low of 0.44 with an average of 0.52. Over the three-year period preceding December 15, 1997, the Historical Trading Ratio ranged from a high of 0.79 to a low of 0.44 with an average of 0.63. The ratio on December 15, 1997 was 0.52.

Contribution Analysis. Salomon Smith Barney reviewed the relative contributions of each of AEP and CSW to estimated net income of the combined companies for each of the years from 1997 through 2006, to LTM book value of the combined companies, to 1999 estimated book value for the combined companies and to market equity value of the combined companies as of December 15, 1997. This analysis showed that CSW is expected to contribute a percentage of the combined company's net income ranging from approximately 34% to approximately 40% in fiscal 1997 to 2003 before leveling off at approximately 39% in the years 2004 to 2006. This analysis also showed that CSW's contribution to LTM book value and 1999 estimated book value were approximately 44% and 42%, respectively, and that its contribution to market equity value at December 15, 1997 was approximately 37%. CSW stockholders would own approximately 40% of the outstanding shares of the combined companies based upon the Exchange Ratio.

Pro Forma Analysis of the Merger. Salomon Smith Barney analyzed the pro forma impact of the Merger on an earnings per share ("EPS") basis to AEP's shareholders and on an EPS and dividends per share ("DPS") basis to CSW's stockholders for the fiscal years ended December 31, 2000 through 2006. The analysis was performed utilizing stand-alone earnings estimated for the years 2000 through 2006 for

AEP and CSW based on financial projections prepared by AEP management taking into account the synergies expected to be derived from the Merger as estimated by AEP but excluding one-time costs. Based upon such analysis, the Merger would be somewhat dilutive to AEP shareholders for the years 2000-2002 and somewhat accretive for the remaining years of the forecast. Salomon Smith Barney noted that the transaction would generally produce EPS accretion of 10% or more each year for CSW stockholders, but would result in a lower dividend per original CSW Share of more than 10% through 2003, the reduction continuing to decline thereafter.

The foregoing summary does not purport to be a complete description of the analyses performed by Salomon Smith Barney or of its presentations to AEP's Board of Directors. Such summary does constitute a complete summary, in all material respects, of the material financial analyses furnished by Salomon Smith Barney to the AEP Board on December 17, 1997. The preparation of financial analyses and fairness opinions is a complex process involving subjective judgments and is not necessarily susceptible to partial analysis or summary description. Salomon Smith Barney made no attempt to assign specific weights to particular analyses or factors considered, but rather made qualitative judgments as to the significance and relevance of the analyses and factors considered. Accordingly, Salomon Smith Barney believes that its analyses (and the summary set forth above) must be considered as a whole, and that selecting portions of such analyses and of the factors considered by Salomon Smith Barney, without considering all of such analyses and factors, could create a misleading or incomplete view of the processes underlying the analyses conducted by Salomon Smith Barney and its opinion. With regard to the comparable public company analysis and the comparable transaction analysis summarized above, Salomon Smith Barney selected comparable public companies on the basis of various factors, including the size of the public company and similarity of the line of business; however, no public company or transaction utilized as a comparison is identical to CSW or AEP, any business segment of CSW or AEP or the Merger. As a result, the comparable public company analysis and the comparable transaction analysis are not purely mathematical, but also take into account differences in financial and operating characteristics of the Comparable Companies and other factors that could affect the transaction or public trading value of the Comparable Companies and transactions to which CSW and AEP, the business segments of CSW and AEP and the Merger are being compared. In its analyses, Salomon Smith Barney made numerous assumptions with respect to CSW, AEP, industry performance, general business, economic, market and financial conditions and other matters, many of which are beyond the control of CSW and AEP, including (in addition to those specifically mentioned in the Salomon Smith Barney opinion) that there would be no material changes in AEP's or CSW's assets, financial condition, results of operations or prospects and that U.S. economic conditions, the financial markets and the mergers and acquisitions market, generally, would continue as currently existing with no material changes. Any estimates contained in Salomon Smith Barney's analyses are not necessarily indicative of actual values or predictive of future results or values, which may be significantly more or less favorable than those suggested by such analyses. Estimates of values of companies do not purport to be appraisals or necessarily to reflect the prices at which companies may actually be sold. Because such estimates are inherently subject to uncertainty, none of CSW, AEP, CSW's Board of Directors, AEP's Board of Directors, Salomon Smith Barney or any other person assumes responsibility if future results or actual values differ materially from the estimates. Salomon Smith Barney's analyses were prepared solely as part of Salomon Smith Barney's analysis of the fairness of the consideration to be paid by AEP in the Merger and were provided to AEP's Board of Directors in that connection. The opinion of Salomon Smith Barney was one of the factors taken into consideration by AEP's Board of Directors in making its determination to approve the Merger Agreement and the Merger.

Salomon Smith Barney is an internationally recognized investment banking firm engaged, among other things, in the valuation of businesses and their securities in connection with mergers and acquisitions, restructurings, leveraged buyouts, negotiated underwritings, competitive biddings, secondary distributions of listed and unlisted securities, private placements and valuations for estate, corporate and other purposes. AEP selected Salomon Smith Barney to act as its financial advisor on the basis of Salomon Smith Barney's international reputation and Salomon Smith Barney's familiarity with AEP. Salomon Smith

Barney or its affiliates had previously rendered investment banking and financial advisory services to AEP and CSW, for which such entity received customary compensation. In addition, in the ordinary course of its business, Salomon Smith Barney may trade the debt and equity securities of both CSW and AEP for its own account and for the accounts of customers and, accordingly, may at any time hold a long or short position in such securities.

Pursuant to the Salomon Engagement Letter, AEP will pay Salomon Smith Barney the following fees: (a) a quarterly retainer of $100,000 for each quarter that Salomon Smith Barney is actively providing financial advisory and investment banking services to AEP (pursuant to which $2.0 million has been paid as of the date of this Joint Proxy Statement/Prospectus); plus (b) an additional fee of $2.5 million, which became payable upon execution of the Merger Agreement (which has been paid); plus (c) an additional fee of $2.5 million, which will become payable upon approval of the Merger Agreement by the stockholders of CSW and approval of the Share Issuance and the Charter Amendment by the shareholders of AEP; plus (d) an additional fee of $12.5 million (less any amounts paid pursuant to (a), (b) and (c) above) upon closing of the Merger. AEP has also agreed to reimburse Salomon Smith Barney for its reasonable travel and other out-of-pocket expenses incurred in connection with its engagement (including the reasonable fees and disbursements of its counsel) and to indemnify Salomon Smith Barney against certain liabilities and expenses relating to or arising out of its engagement, including certain liabilities under the federal securities laws.

As noted under the captions "THE MERGER—Recommendations of the Boards of Directors; Reasons for the Merger" and "—Recommendations of the Boards of Directors," the fairness opinion of Salomon Smith Barney was one of several factors considered by AEP's Board of Directors in determining to approve the Merger Agreement and the Merger. The amount of consideration payable in the Merger was determined by arms'-length negotiations between AEP and CSW, in consultation with their respective financial advisors and other representatives, and was not established by such financial advisors.

Opinion of Financial Advisor to CSW

Morgan Stanley was retained by CSW to act as its financial advisor in connection with the Merger. Morgan Stanley is an internationally recognized investment banking firm and was selected by CSW based on Morgan Stanley's experience and expertise. On December 21, 1997, Morgan Stanley rendered to CSW's Board of Directors an oral opinion, which was subsequently confirmed in writing, to the effect that, as of such date and based on and subject to certain matters stated therein, the Exchange Ratio provided for under the Merger Agreement was fair from a financial point of view to the holders of CSW Shares.

The full text of Morgan Stanley's written opinion, dated the date of this Joint Proxy Statement/ Prospectus, which sets forth the assumptions made and matters considered and the limits of the review undertaken, is attached as Annex III to this Joint Proxy Statement/Prospectus and is incorporated herein by reference. Holders of CSW Shares are urged to, and should, read the opinion carefully and in its entirety. Morgan Stanley's opinion addresses the fairness of the Exchange Ratio provided for under the Merger Agreement from a financial point of view to the holders of CSW Shares. It does not address any other aspect of the Merger nor does it constitute a recommendation to any holder of CSW Shares as to how to vote at the CSW Meeting. The summary of the opinion of Morgan Stanley set forth in this Joint Proxy Statement/ Prospectus is qualified in its entirety by reference to the full text of such opinion.

For purposes of the opinion set forth herein, Morgan Stanley, among other things: (i) reviewed certain publicly available financial statements and other information of CSW and AEP; (ii) reviewed certain internal financial statements and other financial and operating data concerning CSW and AEP prepared by their respective managements; (iii) analyzed certain financial projections prepared by the managements of CSW and AEP, respectively; (iv) discussed the past and current operations and financial condition and the prospects of CSW and AEP with senior executives of CSW and AEP, respectively; (v) reviewed the reported prices and trading activity for CSW Shares and AEP Shares; (vi) discussed certain regulatory issues relating to the proposed Merger with senior executives of CSW and AEP; (vii) compared the financial performance of CSW and AEP and the prices and trading activity of CSW Shares and AEP Shares with that of certain other comparable publicly-traded companies and their securities; (viii) reviewed the financial terms, to the extent publicly available, of certain comparable merger and acquisition transactions; (ix) reviewed the pro forma impact of the Merger on AEP's earnings per share, cash flow, consolidated capitalization and financial ratios; (x) participated in discussions and negotiations among representatives of CSW and AEP and their financial and legal advisors; (xi) reviewed the Merger Agreement and certain related documents; (xii) reviewed and discussed with CSW and AEP an analysis prepared by CSW and AEP with the assistance of a third-party consultant regarding estimates of the amount and timing of synergies and cost savings estimated to be derived from the Merger; and (xiii) performed such other analyses as Morgan Stanley has deemed appropriate.

Morgan Stanley assumed and relied upon without independent verification the accuracy and completeness of the information reviewed by Morgan Stanley for the purposes of its opinion. With respect to the financial projections and the estimates of the amount and timing of synergies and cost savings estimated to be derived from the Merger, Morgan Stanley assumed that they have been reasonably prepared on bases reflecting the best currently available estimates and judgments of the future financial performance of CSW and AEP. Morgan Stanley did not make any independent valuation or appraisal of the assets or liabilities of CSW, nor was Morgan Stanley furnished with any such appraisals. In addition, Morgan Stanley assumed that the Merger will be consummated in accordance with the terms set forth in the Merger Agreement, including, among other things, that the Merger will be accounted for as a "pooling of interests" business combination in accordance with U.S. generally accepted accounting principles and the Merger will be treated as a tax-free reorganization and/or exchange, each pursuant to the Internal Revenue Code of 1986 (the "Code"). Morgan Stanley's opinion is necessarily based on economic, market and other conditions as in effect on, and the information made available to Morgan Stanley as of, the date of its opinion.

The following is a brief summary of the material analyses performed by Morgan Stanley in connection with Morgan Stanley's presentation and opinion to the CSW Board on December 21, 1997:

Comparable Public Company Analysis. As part of its analysis, Morgan Stanley compared certain financial information of CSW with that of a group of publicly traded electric utility companies, including Dominion Resources, Inc., Entergy Corporation, PP&L Resources, Inc., and Texas Utilities Company (collectively, the "CSW Comparable Companies"), and also compared certain financial information of AEP with that of a group of publicly traded electric utility companies, including CINergy Corp., FPL Group, Inc., LG&E Energy Corporation, Northern States Power Company and PacifiCorp (collectively, the "AEP Comparable Companies"). Such financial information included the ratio of price to LTM ended September 30, 1997, forecasted 1998 and forecasted 1999 earnings multiples, price to book value multiple, price to LTM cash flow from operations multiple and dividend yield. Such analyses indicated that as of December 19, 1997 and based on a compilation of earnings projections by securities research analysts as of December 19, 1997, CSW and AEP traded at 13.0 and 16.6 times historical LTM earnings, respectively; 13.7 and 15.2 times forecasted earnings for the calendar year 1998, respectively; 13.3 and 14.7 times forecasted earnings for the calendar year 1999, respectively; 1.5 and 2.1 times book value as of the quarter ended September 30, 1997, respectively; 6.2 and 8.0 times historical LTM cash flow from operations, respectively; and dividend yields of 6.7% and 4.6%, respectively. Morgan Stanley noted that, based on a compilation of earnings projections by securities research analysts as of December 19, 1997, the CSW Comparable Companies and the AEP Comparable Companies traded in a range of 12.4 to 17.8 and 14.7 to 23.1 times historical LTM earnings, respectively; 10.8 to 12.9 times and 14.2 and 15.7 times 1998 forecasted earnings, respectively; 10.5 to 12.6 and 13.6 and 15.0 times 1999 forecasted earnings, respectively; 1.0 to 1.5 and 1.8 and 2.4 times book value as of the quarter ended September 30, 1997, respectively; and had dividend yields of 5.4% to 7.4% and 3.3% to 4.9%, respectively.

No company utilized in the comparable public company analysis is identical to CSW or AEP. Accordingly, an analysis of the results of the foregoing necessarily involves complex considerations and judgments concerning differences in financial and operating characteristics of CSW and AEP and other factors that could affect the public trading value of the companies to which they are being compared. In evaluating the CSW Comparable Companies and the AEP Comparable Companies, Morgan Stanley made judgments and assumptions with regard to industry performance, general business, economic, market and financial conditions and other matters, many of which are beyond the control of CSW or AEP, such as the impact of competition on CSW or AEP and the industry generally, industry growth and the absence of any adverse material change in the financial conditions and prospects of CSW or AEP or the industry or in the financial markets in general. Mathematical analysis (such as determining the mean or median) is not, in itself, a meaningful method of using comparable company data.

Trading Ratio Analysis. Morgan Stanley also reviewed the ratio of the trading prices of CSW Shares to AEP Shares over the intervals of three months, six months, one year, two years and three years prior to the announcement of the Merger. Such ratios were in the range of 0.47 to 0.63. Based on the closing price of CSW Shares and AEP Shares on December 19, 1997 (the last trading day prior to December 21, 1997) of $26.00 and $52.00, respectively, the ratio was 0.50.

Discounted Cash Flow Analysis. Morgan Stanley performed a discounted cash flow analysis of CSW and AEP based on certain financial projections provided by the respective managements for each company for the period 1997 through 2006 and 1997 through 2007, respectively. Unlevered free cash flow of each company was calculated as net income available to common stockholders plus the aggregate of preferred stock dividends, depreciation and amortization, deferred taxes, and other noncash expenses and after-tax net interest expense less the sum of capital expenditures and investment in noncash working capital. Morgan Stanley calculated terminal values by applying a range of perpetual growth rates to the unlevered free cash flow in fiscal 2006 and 2007, respectively, and the cash-flow streams and terminal values were then discounted to the present using a range of discount rates representing an estimated range of the weighted average cost of capital for CSW and AEP. Based on this analysis, Morgan Stanley calculated per share values for CSW ranging from $18.95 to $24.82 and for AEP ranging from $46.64 to $55.71.

Analysis of Selected Precedent Transactions. Using publicly available information, Morgan Stanley considered announced or completed transactions in the electric utility industry, which were deemed to be comparable to the Merger including KU Energy Corporation and LG&E Energy Corporation, DQE, Inc. and Allegheny Power System, Inc., Kansas City Power & Light Company and Western Resources, Inc., Potomac Electric Power Company and Baltimore Gas & Electric Company and CIPSCO Incorporated and Union Electric Company (collectively, the "Electric Utility Transactions"). Morgan Stanley compared certain financial and market statistics of the Electric Utility Transactions to the Merger. The premium to unaffected market price (i.e., the unaffected market price one day prior to the announcement of the Transaction) ranged from 21% to 34%, the price to book value multiple ranged from 1.7 to 2.4 times, the LTM price to earnings multiple ranged from 15.4 to 19.8 times and the LTM operating cash flow multiple ranged from 7.5 to 8.4 times. Based on this analysis, Morgan Stanley calculated per share values for CSW ranging from $28.34 to $32.82.

No transaction utilized as a comparison in the analysis of selected precedent transactions is identical to the Merger in both timing and size. Accordingly, an analysis of the results of the foregoing necessarily involves complex considerations and judgments concerning differences in financial and operating characteristics of CSW and other factors that would affect the acquisition value of the companies to which it is being compared. In evaluating the precedent transactions, Morgan Stanley made judgments and assumptions with regard to industry performance, global business, economic, market and financial conditions and other matters, many of which are beyond the control of CSW, such as the impact of competition on CSW and the industry generally, industry growth and the absence of any adverse material change in the financial conditions and prospects of CSW or the industry or the financial markets in general. Mathematical analysis (such as determining the mean or median) is not, in itself, a meaningful method of using precedent transactions data.

Contribution Analysis. Morgan Stanley reviewed the pro forma effect of the Merger and computed the contribution attributable to CSW and AEP to the combined company's pro forma projected financial results for 1997. Such financial results included: sales; operating income; EBITDA; earnings; cash flow from operations; and book value. The computation showed, among other things, that CSW would contribute to the combined company's approximately 46% of sales, 40% of operating income, 43% of EBITDA, 28% of earnings, 39% of cash flow from operations, and 43% of book value. Morgan Stanley calculated that the Exchange Ratio would result in pro forma ownership of the combined company for holders of CSW common stock equal to approximately 40%.

Pro Forma Analysis of the Merger. Morgan Stanley reviewed the pro forma impact of the Merger on AEP's EPS for the fiscal years ended 1998 through 2001. The analysis was performed assuming completion of the Merger at the beginning of this period, utilizing stand-alone earnings estimated for the fiscal years ended 1998 through 2001 for CSW and AEP based on certain financial projections prepared by the respective managements of each company taking into account the synergies and cost savings expected to be derived from the Merger as estimated by CSW and AEP. Based on such analysis, the Merger would average less than 1.0% dilution to AEP's stockholders for the period 1998 through 2001 on an EPS basis.

In connection with its opinion dated the date of this Joint Proxy Statement/Prospectus, Morgan Stanley confirmed the appropriateness of its reliance on the analyses performed in connection with its opinion delivered on December 21, 1997 by performing procedures to update certain of such analyses and by reviewing the assumptions on which such analyses were based and the factors considered in connection therewith. The preparation of a fairness opinion is a complex process and is not necessarily susceptible to a partial analysis or summary description. Morgan Stanley considered the results of all of its analysis as a whole and did not attribute any particular weight to an analysis or factor considered by it. Morgan Stanley believes that selecting portions of its analyses, without considering all analyses, would create an incomplete view of the process underlying its opinion. In addition, Morgan Stanley may have given various analyses more or less weight than other analyses, and may have deemed various assumptions more or less probable than other assumptions, so that the ranges of valuations resulting for any particular analysis described above should not be taken to be Morgan Stanley's view of the actual value of CSW and AEP.

In performing its analyses, Morgan Stanley made numerous assumptions with respect to industry performance, general business and economic conditions and other matters, many of which are beyond the control of CSW and AEP, including (in addition to those specifically mentioned in the Morgan Stanley opinion) that there would be no material changes in AEP's or CSW's assets, financial condition, results of operations or prospectus and that U.S. economic conditions, the financial markets and the mergers and acquisitions market, generally, would continue as currently existing with no material changes. The analyses performed by Morgan Stanley are not necessarily indicative of actual value, which may be significantly more or less favorable than suggested by such analyses. Such analyses were prepared solely as part of Morgan Stanley's analysis of the fairness of the Exchange Ratio, pursuant to the Merger Agreement, from a financial point of view to the holders of CSW Shares and were provided to the CSW Board in connection with the delivery of Morgan Stanley's written opinion dated December 21, 1997. The analyses do not purport to be appraisals or to reflect the prices at which CSW might actually be sold. In addition, as described above, Morgan Stanley's opinion and presentation to the CSW Board were one of many factors taken into consideration by the CSW Board in making its determination to approve the Merger. Consequently, the Morgan Stanley analyses described above should not be viewed as determinative of the opinion of the CSW Board or the view of the management of CSW with respect to the value of CSW or of whether the CSW Board would have been willing to agree to a different exchange ratio. The Exchange Ratio pursuant to the Merger Agreement was determined through negotiations between CSW and AEP and approved by the CSW Board and the AEP Board.

As part of its investment banking business, Morgan Stanley is regularly engaged in the valuation of businesses and securities in connection with mergers and acquisitions, negotiated underwritings, competitive biddings, secondary distributions of listed and unlisted securities, private placements and valuation for estate, corporate and other purposes. In the ordinary course of its business, Morgan Stanley and its affiliates may actively trade the debt and equity securities of CSW and AEP for their own account and for the accounts of customers and, accordingly, may at any time hold a long or short position in such securities. In the past, Morgan Stanley has provided financial advisory and financing services to CSW and AEP, and their affiliates, for which services Morgan Stanley has received customary fees.

Morgan Stanley has been retained by CSW to act as financial advisor to CSW with respect to the Merger. Pursuant to a letter agreement dated December 19, 1997 between CSW and Morgan Stanley, Morgan Stanley is entitled to (i) an advisory fee for its time and efforts expended in connection with the engagement, which is estimated to be between $1,500,000 and $2,000,000 and which is payable in the event the transaction is not consummated and (ii) a transaction fee equal to approximately $18,250,000, which is payable as follows: one-third upon the execution of the definitive transaction agreement, one-third upon approval of the transaction by CSW's shareholders and one-third upon closing of the transaction. Any amounts paid or payable to Morgan Stanley as advisory or announcement fees will be credited against the transaction fee. CSW has also agreed to reimburse Morgan Stanley for its expenses, including expenses of its counsel, and to indemnify Morgan Stanley and its affiliates against certain liabilities and expenses, including liabilities under federal securities laws.

Merger Consideration

Pursuant to the Merger Agreement, subject to certain provisions as described herein with respect to shares owned by CSW, AEP or any subsidiary of CSW or AEP, and with respect to fractional shares, each issued and outstanding CSW Share will be converted into the right to receive from AEP 0.60 of an AEP Share.

Fractional AEP Shares will not be issued in the Merger. Holders of CSW Shares otherwise entitled to a fractional AEP Share will be paid cash in lieu of such fractional share determined and paid as described in "Fractional Shares" below.

The Exchange Ratio was determined by and through negotiations between AEP and CSW, each of which was advised with respect to such negotiations by its respective financial advisor. Based on the number of CSW Shares and the number of CSW stock options outstanding on the CSW Record Date, a maximum of 130,000,000 AEP Shares may be issued in respect of CSW Shares in the Merger and 700,000 shares would be reserved for issuance upon exercise of CSW options assumed by AEP pursuant to the Merger Agreement.

Any CSW Shares owned by CSW or any of its subsidiaries or by AEP, Sub or any other subsidiary of AEP will automatically be cancelled at the Effective Time and will cease to exist. The securities of CSW's subsidiaries will remain outstanding after consummation of the Merger.

Effective Time of the Merger

The Merger will become effective upon the filing and acceptance of the Certificate of Merger with the Secretary of State of the State of Delaware or such later date as is specified in such Certificate. The filing of the Certificate of Merger will occur as soon as practicable following the satisfaction or, if permissible, waiver of the conditions set forth in the Merger Agreement. See "THE MERGER AGREEMENT — Conditions to the Consummation of the Merger".

The Merger Agreement provides that, subject to certain limitations, the Merger Agreement may be terminated by one or all parties at any time prior to the filing of the Certificate of Merger with the Delaware Secretary of State if, among other reasons, the Merger has not been consummated on or before December 31, 1999 (or June 30, 2000 if this deadline is extended pursuant to the terms of the Merger Agreement) notwithstanding approval of the Merger Agreement by the stockholders of CSW or the approval of the Charter Amendment or the Share Issuance by the shareholders of AEP. See "THE MERGER AGREEMENT — Termination".

Conversion of Shares; Procedures for Exchange of Certificates

The conversion of CSW Shares into the right to receive AEP Shares will occur at the Effective Time of the Merger.

As soon as reasonably practicable after the Effective Time, a third party exchange agent selected by AEP and reasonably satisfactory to CSW (the "Exchange Agent") will send a transmittal form (the "Letter of Transmittal") to each record holder of CSW Shares. The Letter of Transmittal will contain instructions with respect to the surrender of certificates which prior thereto represented CSW Shares in exchange for certificates representing the AEP Shares or the amount of cash in lieu of a fractional interest in an AEP Share for which the shares represented by the certificates so surrendered are exchangeable pursuant to the Merger Agreement.

CSW STOCKHOLDERS SHOULD NOT FORWARD CSW STOCK CERTIFICATES TO THE EXCHANGE AGENT UNTIL THEY HAVE RECEIVED TRANSMITTAL FORMS.

As soon as practicable after the Effective Time, each holder of an outstanding certificate or certificates which prior thereto represented CSW Shares shall, upon surrender to the Exchange Agent of such certificate or certificates and acceptance thereof by the Exchange Agent, be entitled to a certificate or certificates representing the number of whole AEP Shares, calculated based on the Exchange Ratio and rounded down to the nearest whole number, and the amount of cash, if any, into which the aggregate number of CSW Shares previously represented by such certificate or certificates surrendered shall have been converted. The Exchange Agent shall accept such certificates upon compliance with such reasonable terms and conditions as the Exchange Agent may impose to effect an orderly exchange thereof in accordance with normal exchange practices. After the Effective Time, there will be no further transfer on the records of CSW or its transfer agent of certificates representing CSW Shares and if such certificates are presented for transfer, they shall be cancelled against delivery of certificates for AEP Shares (and cash, if any, in lieu of fractional AEP Shares) pursuant to the Merger Agreement. Until surrendered in accordance with the Merger Agreement, each certificate for CSW Shares will be deemed at any time after the Effective Time to represent only the right to receive upon such surrender the consideration contemplated by the Merger Agreement. No interest will be paid or will accrue on any cash payable in lieu of any fractional AEP Shares.

No dividends or other distributions declared or made after the Effective Time with respect to AEP Shares with a record date after the Effective Time will be paid to the holder of any unsurrendered certificate for CSW Shares with respect to the CSW Shares formerly represented thereby, and no cash payment in lieu of fractional shares shall be paid to any such holder, until the surrender of such certificate in accordance with the Merger Agreement. Following surrender of any such certificate, there shall be paid without interest to the holder of such certificate (i) a certificate or certificates representing whole AEP Shares issued in exchange therefor (ii) the amount of any cash payable with respect to any fraction of an AEP Share to which such holder is entitled pursuant to the Merger Agreement (iii) the amount of dividends or other distributions with a record date after the Effective Time theretofore paid with respect to such whole AEP Shares and (iv) at the appropriate payment date, the amount of dividends or other distributions with a record date after the Effective Time but prior to such surrender and a payment date subsequent to such surrender payable with respect to such whole AEP Shares.

Fractional Shares

No certificates or scrip representing fractional AEP Shares will be issued upon surrender for exchange of certificates formerly representing CSW Shares, and such fractional share interests will not entitle the owner thereof to vote or to any rights of a shareholder of AEP. In lieu of any such fractional shares, each holder of CSW Shares upon surrender of a certificate for exchange pursuant to the Merger Agreement will be paid an amount in cash (without interest), determined as follows: pursuant to instructions from AEP, the Exchange Agent will determine the number of fractional shares allocable to all holders of CSW Shares pursuant to the Merger Agreement, will aggregate all such fractional shares into whole AEP Shares, will sell such whole AEP Shares in the open market at then prevailing prices on behalf of the holders who would otherwise be entitled thereto and will distribute to each holder, at the time of surrender of such holder's CSW Share certificates, such holder's ratable share of such proceeds, after withholding United States federal income taxes and any applicable transfer taxes. All brokers' fees and commissions and fees of the Exchange Agent incurred in connection with such sale will be paid by AEP. For this purpose, shares of any holder represented by two or more certificates may be aggregated, and in no event will any holder be paid any amount in respect of more than one AEP Share.

Material U.S. Federal Income Tax Consequences

In the opinion of Christy & Viener, tax counsel to CSW, the following discussion accurately describes the material United States federal income tax consequences of the Merger to the holders of CSW Shares and is based upon current provisions of the Code, existing regulations thereunder and current administrative rulings and court decisions, all of which are subject to change. In addition, this discussion summarizes the tax opinions being delivered to CSW and AEP by Christy & Viener and Simpson Thacher & Bartlett, respectively, which have been filed as exhibits to the Registration Statement of which this Joint Proxy Statement/Prospectus is a part. This discussion does not address all of the Merger's United States federal income tax consequences that may be relevant to particular holders, including holders that are subject to special tax rules such as dealers in securities, foreign persons, mutual funds, insurance companies, tax-exempt entities and holders who do not hold their shares as capital assets. Holders of CSW Shares are advised and expected to consult their own tax advisors regarding the United States federal income tax consequences of the Merger in light of their personal circumstances and the consequences under state, local and foreign tax laws.

AEP has received from its counsel, Simpson Thacher & Bartlett, an opinion to the effect that the Merger will be treated for United States federal income tax purposes as a reorganization within the meaning of Section 368(a) of the Code, that AEP, Sub and CSW each will be a party to the reorganization within the meaning of Section 368(b) of the Code and that AEP, Sub and CSW will not recognize any gain or loss as a result of the Merger. CSW has received from its tax counsel, Christy & Viener, an opinion to the effect that the Merger will be treated for United States federal income tax purposes as a reorganization within the meaning of Section 368(a) of the Code, that AEP, Sub and CSW each will be a party to the reorganization within the meaning of Section 368(b) of the Code, and that stockholders of CSW will not recognize any gain or loss upon the receipt of AEP Shares for their CSW Shares, other than with respect to cash received in lieu of fractional shares. Such opinions are subject to certain assumptions and based on certain representations of AEP, Sub and CSW. Stockholders of CSW should be aware that such opinions are not binding on the Internal Revenue Service (the "IRS"), and no assurance can be given that the IRS will not adopt a contrary position or that a contrary IRS position would not be sustained by a court.

Since, in the opinion of counsel for AEP and CSW, the Merger will qualify as a reorganization under Section 368(a) of the Code, the following United States federal income tax consequences will result:

(a) no gain or loss will be recognized by AEP, Sub or CSW in connection with the Merger;

(b) no gain or loss will be recognized by a holder of CSW Shares upon the exchange of all such holder's shares of CSW Shares solely for AEP Shares in the Merger;

(c) the aggregate basis of the AEP Shares received by a CSW stockholder in the Merger (including any fractional share deemed received) will be the same as the aggregate basis of the CSW Shares surrendered in exchange therefor;

(d) the holding period of the AEP Shares received by a CSW stockholder in the Merger (including any fractional share deemed received) will include the holding period of the CSW Shares surrendered in exchange therefor; provided that such CSW Shares are held as capital assets at the Effective Time; and

(e) a stockholder of CSW who receives cash in lieu of a fractional share will recognize gain or loss equal to the difference, if any, between such stockholder's basis in the fractional share (as described in paragraph (c) above) and the amount of cash received. Such gain or loss will be eligible for long-term capital gain or loss treatment if the CSW Shares are held by such stockholder as a capital asset at the Effective Time, and the holding period for a fractional share (as described in paragraph (d) above) is more than one year at the Effective Time. If the holding period for a fractional share is more than 18 months at the Effective Time, a maximum tax rate of 20% will apply to any such capital gain if recognized by a CSW stockholder who is an individual.

UNDER THE TERMS OF THE MERGER AGREEMENT AEP AND/OR CSW MAY WAIVE THE REQUIREMENT THAT SUCH PARTIES RECEIVE THE BRING-DOWN OPINIONS OF TAX COUNSEL DESCRIBED ABOVE AT CLOSING. IF THE RECEIPT OF SUCH TAX OPINIONS AT CLOSING IS WAIVED BY EITHER PARTY, AEP AND CSW WILL RECIRCULATE THIS JOINT PROXY STATEMENT/PROSPECTUS TO DISCLOSE ANY SUCH WAIVER AND ALL RELATED MATERIAL DISCLOSURE, INCLUDING RISKS TO INVESTORS, AND RESOLICIT THE VOTES OF THE RESPECTIVE STOCKHOLDERS OF AEP AND CSW.

Anticipated Accounting Treatment

The Merger is expected to be accounted for using the "pooling of interests" method of accounting for business combinations pursuant to Opinion No. 16 of the Accounting Principles Board. The pooling of interests method of accounting assumes that the combining companies have been merged from inception, and the historical financial statements for periods prior to consummation of the Merger are restated as though the companies had been combined from inception. See the "Unaudited Pro Forma Combined Condensed Financial Statements."

The receipt on the closing date by AEP of a letter from Deloitte & Touche LLP and by CSW of a letter from Arthur Andersen LLP, their respective independent accountants, stating that the transaction will qualify as a pooling is a condition to the consummation of the Merger. In addition, the Merger Agreement provides that each person who may be deemed an affiliate of CSW or AEP will enter into an agreement with AEP not to sell or otherwise transfer any CSW Shares or AEP Shares, as the case may be, within 30 days prior to the Effective Time or any AEP Shares thereafter prior to the publication of financial results that include at least 30 days of post-Merger combined operations of AEP and CSW. Forms of such agreements ("Affiliate's Agreements") are attached as Annexes B and C to the Merger Agreement, a copy of which is itself attached to this Joint Proxy Statement/Prospectus as Annex I. In accordance with the provisions of the Merger Agreement, AEP and CSW will each use commercially reasonable efforts to obtain, not later than 10 days prior to the date of the respective shareholders' meetings, executed Affiliate's Agreements from all persons known to the managements of AEP or CSW to be affiliates of either corporation.

Interests of Certain Persons in the Merger

In considering the CSW Board's recommendation that you vote in favor of the Merger, CSW stockholders should be aware that the officers of CSW, including some officers who are also directors, and nonemployee directors of CSW have certain interests in the Merger that are different from, or in addition to, the interests of stockholders of CSW generally.

Ownership of CSW Shares; Stock Options

As of December 31, 1997, directors and executive officers of CSW beneficially owned an aggregate of 486,165 CSW Shares. As of December 31, 1997, directors and executive officers of CSW held options to purchase an aggregate of 561,191 CSW Shares, of which options to purchase 239,258 CSW Shares were exercisable. See "The Merger Agreement—Stock Based Compensation and Employee Benefit Plans;" and "Compensation Information of Directors and Executive Officers of CSW."

CSW Long-Term Incentive Plan and Change in Control Agreements.

CSW's Amended and Restated 1992 Long-Term Incentive Plan (the "CSW Incentive Plan") provides for awards of stock options, stock appreciation rights, restricted stock, phantom stock, and performance unit awards to employees selected by the CSW compensation committee. See "THE CSW MEETING—ADDITIONAL MATTERS—Executive Compensation." As of December 31, 1997, the executive officers of CSW had received awards of restricted stock, stock options and performance units, as described elsewhere in this Joint Proxy Statement/Prospectus. Upon a Change in Control (as defined in the CSW Incentive Plan), the awards previously granted to those employees will become fully exercisable, fully vested, or fully earned. A Change in Control, includes, among other things, a merger, acquisition or consolidation following which the stockholders of CSW own less than 75% of the surviving entity. Consummation of the Merger will constitute a Change in Control under the CSW Incentive Plan.

Pursuant to CSW Board of Directors approval in October 1996, CSW also has Change in Control Agreements (the "Change in Control Agreements") with 16 key employees, including those individuals named in the CSW Summary Compensation Table. See "The CSW Meeting—Additional Matters—Cash and Other Forms of Compensation." The purpose of the Change in Control Agreements is to assure the objective judgment and to retain the loyalty of these key employees in the event of a Change in Control (as defined) of CSW. A Change in Control includes, among other things, any person gaining ownership or control of 25% or more of the outstanding shares of CSW's voting stock or the closing of any merger, acquisition or consolidation following which the former shareholders of CSW own less than 75% of the surviving entity. The Merger will constitute such a Change in Control.

The Change in Control Agreements entitle such employees, in certain circumstances, including but not limited to, a termination by CSW within three years after a Change in Control (prior to the expiration of the Change in Control Agreements), to receive (i) a lump sum payment equal to two to four times of their base salary plus target bonus, (ii) enhanced non-qualified retirement benefits, (iii) continued health and other welfare benefits for up to three years and (iv) various other non-qualified benefits. Such employees are also eligible for an additional payment, if required, to make them whole for any excise tax imposed by Section 4999 of the Code.

The total amount that may be payable to CSW's officers and directors in connection with the Merger pursuant to the Change in Control Agreements is approximately $48.4 million (including, $10.4 million payable under the CSW Incentive Plan), plus any additional payments that may be necessary to cover excise tax liabilities (including any gross-up) under Section 4999 of the Code in connection with such payments. In order to encourage retention of key executives, and for other business reasons, CSW and AEP are currently evaluating certain modifications to the Change in Control Agreements which are not expected to result in an increase in such payments.

CSW Directors Compensation Plan.

CSW's Directors Compensation Plan (the "CSW Directors Plan") provides cash compensation, phantom stock, deferred compensation and certain other benefits to directors of CSW who are not employees of CSW ("CSW Nonemployee Directors"). The CSW Directors Plan provides that in the event of a Corporate Change (as defined in the CSW Directors Plan), each previously granted phantom stock unit will be converted into one CSW Share. These CSW Shares will be distributed in a lump sum to the CSW Nonemployee Directors. A Corporate Change means the occurrence of (i) a merger or consolidation where CSW is not the surviving corporation (or survives only as subsidiary of an entity other than a previously wholly-owned subsidiary of CSW), (ii) the sale, lease or exchange or agreement to sell, lease or exchange by CSW of 85% or more of its assets to any person or entity (other than a wholly-owned subsidiary of CSW), or (iii) the dissolution or liquidation of CSW. Consummation of the Merger will constitute a Corporate Change under the CSW Directors Plan. As of December 31, 1997, CSW had granted 5,400 phantom stock units to CSW Nonemployee Directors. In the absence of a Corporate Change, phantom stock units granted under the CSW Directors Plan vest at such time as a director ceases to be a member of the CSW Board and are then converted into CSW Shares on a one-for-one basis.

CSW Severance Plan.

CSW's Severance Benefit Plan (the "CSW Severance Plan") provides severance benefits to certain full time employees who are terminated following a restructuring or reorganization (other than those employees covered by Change in Control Agreements). Upon consummation of the Merger, full time employees whose positions are eliminated will receive, among other things, a cash payment based on years of service and certain company paid welfare benefits. Upon consummation of the Merger if all executives are severed, CSW expects to make payments of up to approximately $2.5 million to executive officers under the CSW Severance Plan.

CSW Retention Plan

CSW has entered into retention agreements with a number of executives and managers ("agreement holders") whom it believes are critical to consummating the Merger and are likely to have attractive employment opportunities outside of CSW. There are two types of agreements; one provides for payment of a cash bonus effective on the successful completion of the Merger and the other provides for payment of a cash bonus January 31, 2000. These agreements provide for the payment of a cash bonus within ten days of the successful completion of the Merger, provided in both cases that the agreement holder is still an employee of CSW at the Effective Time, or if the agreement holder has been terminated by the company due to Merger-related staffing decisions. Agreement holders are also entitled to an additional payment, if necessary to make him or her whole for any excise tax, together with interest or penalties, imposed by Section 4999 of the Code on such payments made by CSW. The total cost of these agreements at the time of this Joint Proxy Statement/Prospectus is currently estimated at between $7.5 and $10.0 million, not including any gross-up, if necessary, for excise taxes.

Board of Directors

Pursuant to the Merger Agreement, AEP has agreed to increase the size of the AEP Board of Directors at the Effective Time to 15 directors and take other actions in order to reconstitute the Board to include all then current board members of AEP, Mr. Brooks and four additional outside directors of CSW to be nominated by AEP. The four additional outside directors have not been selected to date.

Director and Officer Indemnification and Insurance

For a period of six years after the Effective Time, AEP has agreed to maintain in effect the current policies of directors' and officers' liability insurance maintained by CSW (or similarly advantageous policies) with respect to claims arising from facts or events which occurred before the Effective Time. AEP will not, however, be obligated to make any annual premium payments for such insurance to the extent such premiums exceed 200% of the greater of the current amount of premiums paid by CSW as of the date of the Merger Agreement or annual premiums for the year in which the Closing occurs paid by CSW.

Until six years from the Effective Time, the certificate of incorporation and bylaws of CSW shall not be amended to reduce or limit the rights of indemnity afforded to the present and former directors and officers of CSW. After the Merger, AEP will at all times exercise the powers granted to it to indemnify the present and former directors, officers, employees and agents of CSW against claims made against them arising from their service in such capacities prior to the Effective Time.

Stock Exchange Listing

It is a condition to the parties' obligations under the Merger Agreement that the AEP Shares issuable pursuant to the Merger Agreement be approved for listing on the NYSE, subject to official notice of issuance.

Restrictions on Resales by Affiliates

The AEP Shares to be received by CSW stockholders in connection with the Merger have been registered under the Securities Act of 1933, and the rules and regulations promulgated thereunder (the "Securities Act") and, except as set forth in this paragraph, may be traded without restriction. The AEP Stock to be issued in connection with the Merger and received by persons who are deemed to be "affiliates" (as that term is defined in Rule 144 under the Securities Act) of CSW prior to the Merger may be resold by them only in transactions permitted by the resale provisions of Rule 145 under the Securities Act (or, in case any such person should become an affiliate of AEP, Rule 144 under the Securities Act) or as otherwise permitted under the Securities Act. Under guidelines published by the SEC, the sale or other disposition of AEP Shares or CSW Shares by an affiliate of either AEP or CSW, as the case may be, within 30 days prior to the Effective Time, or the sale or other disposition of AEP Shares thereafter, prior to the publication of financial results that include at least 30 days of post-Merger combined operations of AEP and CSW (the "Pooling Period") could preclude pooling of interests accounting treatment of the Merger. Accordingly, the Merger Agreement provides that CSW and AEP will use all reasonable efforts to cause each of its affiliates to execute an Affiliate's Agreement to the effect that such persons will not sell, transfer or otherwise dispose of any CSW Shares or AEP Shares, as the case may be, during the Pooling Period (subject to certain exceptions for transactions that would not have an adverse impact on the availability of pooling of interest accounting treatment) and, with respect to affiliates of CSW, that such persons will not sell, transfer or otherwise dispose of AEP Shares at any time in violation of the Securities Act or the rules and regulations promulgated thereunder, including Rule 145. As indicated under "—Anticipated Accounting Treatment," AEP and CSW will each use commercially reasonable efforts to obtain, not later than 10 days prior to the date of the respective shareholders' meetings, executed Affiliate's Agreements from all persons known to the managements of AEP or CSW to be affiliates of such corporations, respectively.

UNAUDITED PRO FORMA COMBINED CONDENSED FINANCIAL STATEMENTS

The following unaudited pro forma combined condensed financial statements reflect the historical condensed balance sheets and condensed statements of income of AEP and CSW, including their respective subsidiaries, after giving effect to the Merger as a pooling of interests. The unaudited pro forma combined condensed balance sheet gives effect to the Merger as though it occurred on the balance sheet date, December 31, 1997.

The unaudited pro forma combined condensed statements of income for the years ended December 31, 1997, 1996 and 1995 give effect to the Merger as if it occurred on January 1, 1995. The statements are based on accounting for the business combination as a pooling of interests and are based on the assumptions in the notes to unaudited pro forma combined condensed financial statements. Certain CSW historical income statement and balance sheet items were reclassified to conform with the presentation expected to be used by AEP after the Merger is completed.

The unaudited pro forma combined condensed financial statements are not necessarily indicative of the results of operations that might have occurred had the Merger actually taken place on January 1, 1995 or the actual financial position that might have resulted had the Merger been consummated on December 31, 1997 or of the future results of operations or financial position of AEP. The unaudited pro forma combined condensed financial statements have been prepared from, and should be read in conjunction with the historical financial statements and related notes thereto of AEP and CSW, incorporated by reference herein. See "WHERE YOU CAN FIND MORE INFORMATION."

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME

Year Ended December 31, 1997

(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$6,161	$3,321		$ 9,482
United Kingdom	—	1,870		1,870
TOTAL OPERATING REVENUES	6,161	5,191		11,352
OPERATING EXPENSES:				
Fuel	1,627	1,177		2,804
Purchased Power	416	89		505
United Kingdom Cost of Sales	—	1,291		1,291
Other Operation	1,228	948		2,176
Maintenance	483	152		635
Depreciation and Amortization	591	491		1,082
Taxes Other Than Federal Income Taxes	491	240		731
Federal Income Taxes	341	106		447
TOTAL OPERATING EXPENSES	5,177	4,494		9,671
OPERATING INCOME	984	697		1,681
NONOPERATING INCOME	60	70		130
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	1,044	767		1,811
INTEREST CHARGES	406	436		842
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	18	12		30
GAIN ON REACQUIRED PREFERRED STOCK OF SUBSIDIARIES	—	10		10
INCOME BEFORE EXTRAORDINARY ITEM	620	329		949
EXTRAORDINARY LOSS—U.K. WINDFALL TAX	(109)	(176)		(285)
NET INCOME	$ 511	$ 153		$ 664
Average Number of Shares Outstanding	189.0	212.1	(84.8)	316.3
EARNINGS PER SHARE (basic and diluted):				
Before Extraordinary Item	$ 3.28	$ 1.55		$ 3.00
Extraordinary Loss	(0.58)	(0.83)		(0.90)
EARNINGS PER SHARE	$ 2.70	$ 0.72		$ 2.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME
Year Ended December 31, 1996
(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$5,849	$3,248		$9,097
United Kingdom	—	1,848		1,848
TOTAL OPERATING REVENUES	5,849	5,096		10,945
OPERATING EXPENSES:				
Fuel	1,601	1,151		2,752
Purchased Power	86	77		163
United Kingdom Cost of Sales	—	1,331		1,331
Other Operation	1,210	780		1,990
Maintenance	503	150		653
Depreciation and Amortization	601	459		1,060
Taxes Other Than Federal Income Taxes	498	255		753
Federal Income Taxes	342	152		494
TOTAL OPERATING EXPENSES	4,841	4,355		9,196
OPERATING INCOME	1,008	741		1,749
NONOPERATING INCOME (LOSS)	2	(7)		(5)
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	1,010	734		1,744
INTEREST CHARGES	381	419		800
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	42	18		60
INCOME FROM CONTINUING OPERATIONS	587	297		884
DISCONTINUED OPERATIONS	—	132		132
NET INCOME	$ 587	$ 429		$1,016
Average Number of Shares Outstanding	187.3	207.5	(83.0)	311.8
EARNINGS PER SHARE (basic and diluted):				
Continuing Operations	$ 3.14	$ 1.43		$ 2.84
Discontinued Operations	—	0.64		0.42
EARNINGS PER SHARE	$ 3.14	$ 2.07		$ 3.26

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME

Year Ended December 31, 1995

(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$5,670	$2,883		$8,553
United Kingdom	—	208		208
TOTAL OPERATING REVENUES	5,670	3,091		8,761
OPERATING EXPENSES:				
Fuel	1,537	1,004		2,541
Purchased Power	88	41		129
United Kingdom Cost of Sales	—	158		158
Other Operation	1,184	551		1,735
Maintenance	542	155		697
Depreciation and Amortization	593	352		945
Taxes Other Than Federal Income Taxes	489	178		667
Federal Income Taxes	272	67		339
TOTAL OPERATING EXPENSES	4,705	2,506		7,211
OPERATING INCOME	965	585		1,550
NONOPERATING INCOME	20	135		155
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	985	720		1,705
INTEREST CHARGES	400	324		724
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	55	19		74
INCOME FROM CONTINUING OPERATIONS	530	377		907
DISCONTINUED OPERATIONS	—	25		25
NET INCOME	$ 530	$ 402		$ 932
Average Number of Shares Outstanding	185.8	191.7	(76.7)	300.8
EARNINGS PER SHARE (basic and diluted):				
Continuing Operations	$ 2.85	$ 1.97		$ 3.02
Discontinued Operations	—	0.13		0.08
EARNINGS PER SHARE	$ 2.85	$ 2.10		$ 3.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED STATEMENT OF INCOME
Year Ended December 31, 1997
(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$3,321		$3,321
United Kingdom	1,870		1,870
Other Diversified	77	$ (77)(A)	—
TOTAL OPERATING REVENUES	5,268	(77)	5,191
OPERATING EXPENSES:			
U.S. Electric Fuel	1,177		1,177
U.S. Electric Purchased Power	89		89
United Kingdom Cost of Sales	1,291		1,291
Other Operation	981	(33)(A)	948
Maintenance	152		152
Depreciation and Amortization	497	(6)(A)	491
Taxes Other Than Federal Income Taxes	195	45 (B)	240
Federal Income Taxes	151	(45)(A,B)	106
TOTAL OPERATING EXPENSES	4,533	(39)	4,494
OPERATING INCOME	735	(38)	697
NONOPERATING INCOME	32	38 (A)	70
INCOME BEFORE INTEREST CHARGES	767	—	767
INTEREST CHARGES:			
Interest on Long-term Debt	333		333
Distributions on Trust Preferred Securities	17		17
Interest on Short-term Debt and Other	86		86
TOTAL INTEREST CHARGES	436		436
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	12		12
GAIN ON REACQUIRED PREFERRED STOCK OF SUBSIDIARIES	(10)		(10)
INCOME BEFORE EXTRAORDINARY ITEM	329		329
EXTRAORDINARY LOSS—U.K. WINDFALL TAX	(176)		(176)
NET INCOME FOR COMMON STOCK	$ 153	$—	$ 153
Average Number of Shares Outstanding	212.1		212.1
EARNINGS PER SHARE (basic and diluted):			
Before Extraordinary Item	$ 1.55		$ 1.55
Extraordinary Loss	(0.83)		(0.83)
EARNINGS PER SHARE	$ 0.72		$ 0.72

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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Year Ended December 31, 1996
(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$3,248		$3,248
United Kingdom	1,848		1,848
Other Diversified	59	$ (59)(A)	—
TOTAL OPERATING REVENUES	5,155	(59)	5,096
OPERATING EXPENSES:			
U.S. Electric Fuel	1,151		1,151
U.S. Electric Purchased Power	77		77
United Kingdom Cost of Sales	1,331		1,331
Other Operation	785	(5)(A)	780
Maintenance	150		150
Depreciation and Amortization	464	(5)(A)	459
Taxes Other Than Federal Income Taxes	178	77 (A,B)	255
Federal Income Taxes	224	(72)(A,B)	152
TOTAL OPERATING EXPENSES	4,360	(5)	4,355
OPERATING INCOME	795	(54)	741
NONOPERATING INCOME (LOSS)	(61)	54 (A)	(7)
INCOME BEFORE INTEREST CHARGES	734	—	734
INTEREST CHARGES:			
Interest on Long-term Debt	325		325
Interest on Short-term Debt and Other	94		94
TOTAL INTEREST CHARGES	419		419
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	18		18
INCOME FROM CONTINUING OPERATIONS	297		297
DISCONTINUED OPERATIONS	132		132
NET INCOME FOR COMMON STOCK	$ 429	$—	$ 429
Average Number of Shares Outstanding	207.5		207.5
EARNINGS PER SHARE (basic and diluted):			
Continuing Operations	$ 1.43		$ 1.43
Discontinued Operations	0.64		0.64
EARNINGS PER SHARE	$ 2.07		$ 2.07

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CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED STATEMENT OF INCOME
Year Ended December 31, 1995
(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$2,883		$2,883
United Kingdom	208		208
Other Diversified	52	$ (52)(A)	—
TOTAL OPERATING REVENUES	3,143	(52)	3,091
OPERATING EXPENSES:			
U.S. Electric Fuel	1,004		1,004
U.S. Electric Purchased Power	41		41
United Kingdom Cost of Sales	158		158
Other Operation	557	(6)(A)	551
Maintenance	155		155
Depreciation and Amortization	353	(1)(A)	352
Taxes Other Than Federal Income Taxes	162	16 (A,B)	178
Federal Income Taxes	92	(25)(A,B)	67
TOTAL OPERATING EXPENSES	2,522	(16)	2,506
OPERATING INCOME	621	(36)	585
NONOPERATING INCOME	99	36 (A)	135
INCOME BEFORE INTEREST CHARGES	720	—	720
INTEREST CHARGES:			
Interest on Long-term Debt	223		223
Interest on Short-term Debt and Other	101		101
TOTAL INTEREST CHARGES	324		324
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	19		19
INCOME FROM CONTINUING OPERATIONS	377		377
DISCONTINUED OPERATIONS	25		25
NET INCOME FOR COMMON STOCK	$ 402	$—	$ 402
Average Number of Shares Outstanding	191.7		191.7
EARNINGS PER SHARE (basic and diluted):			
Continuing Operations	$ 1.97		$ 1.97
Discontinued Operations	0.13		0.13
EARNINGS PER SHARE	$ 2.10		$ 2.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED BALANCE SHEET

December 31, 1997

(in millions)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
ASSETS				
ELECTRIC UTILITY PLANT:				
Production	$ 9,493	$ 5,824		$15,317
Transmission	3,502	1,558		5,060
Distribution	4,654	4,453		9,107
General (including mining assets and nuclear fuel)	1,605	1,577		3,182
Construction Work in Progress	343	184		527
Total Electric Utility Plant	19,597	13,596		33,193
Accumulated Depreciation and Amortization	7,964	5,217		13,181
NET ELECTRIC UTILITY PLANT	11,633	8,379		20,012
OTHER PROPERTY AND INVESTMENTS	1,359	800		2,159
CURRENT ASSETS:				
Cash and Cash Equivalents	91	75		166
Accounts Receivable (net)	668	840		1,508
Fuel	225	65		290
Materials and Supplies	264	172		436
Accrued Utility Revenues	189	76		265
Prepayments and Other	81	78		159
TOTAL CURRENT ASSETS	1,518	1,306		2,824
REGULATORY ASSETS	1,817	1,440		3,257
GOODWILL	—	1,428		1,428
DEFERRED CHARGES	288	98		386
TOTAL	$16,615	$13,451		$30,066

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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UNAUDITED PRO FORMA COMBINED CONDENSED BALANCE SHEET

December 31, 1997

(in millions)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
CAPITALIZATION AND LIABILITIES				
CAPITALIZATION:				
Common Stock	$ 1,293	$ 743	$ 85	$ 2,121
Paid-in Capital	1,779	1,039	(85)	2,733
Retained Earnings	1,605	1,774	(50)	3,329
Total Common Shareholders' Equity	4,677	3,556	(50)	8,183
Cumulative Preferred Stocks of Subsidiaries:				
Not Subject to Mandatory Redemption	47	176		223
Subject to Mandatory Redemption	128	26		154
Certain Subsidiary-obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	—	335		335
Long-term Debt	5,129	3,898		9,027
TOTAL CAPITALIZATION	9,981	7,991	(50)	17,922
OTHER NONCURRENT LIABILITIES	1,246	27		1,273
CURRENT LIABILITIES:				
Preferred Stock and Long-term Debt Due Within One Year	295	32		327
Short-term Debt	555	1,413		1,968
Accounts Payable	353	558		911
Taxes Accrued	381	171		552
Interest Accrued	76	87		163
Obligations Under Capital Leases	101	2		103
Other	323	236	50	609
TOTAL CURRENT LIABILITIES	2,084	2,499	50	4,633
DEFERRED INCOME TAXES	2,561	2,432		4,993
DEFERRED INVESTMENT TAX CREDITS	376	278		654
DEFERRED GAIN ON SALE AND LEASEBACK—ROCKPORT PLANT UNIT 2	231	—		231
DEFERRED CREDITS	136	224		360
TOTAL	$16,615	$13,451		$30,066

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED BALANCE SHEET
December 31, 1997
(in millions)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
ASSETS			
FIXED ASSETS:			
Electric			
Production	$ 5,824		$ 5,824
Transmission	1,558		1,558
Distribution	4,453		4,453
General	1,381	$ 196 (C)	1,577
Construction Work in Progress	184		184
Nuclear Fuel	196	(196)(C)	—
Total Electric	13,596	—	13,596
Other Diversified	250	(250)(D)	—
Total Fixed Assets	13,846	(250)	13,596
Accumulated Depreciation and Amortization	5,218	(1)(D)	5,217
NET FIXED ASSETS	8,628	(249)	8,379
OTHER PROPERTY AND INVESTMENTS	—	800 (D,E,F)	800
CURRENT ASSETS:			
Cash and Cash Equivalents	75		75
Accounts Receivable	916	(76)(G)	840
Fuel	65		65
Materials and Supplies	172		172
Accrued Utility Revenues	—	76 (G)	76
Under-Recovered Fuel Costs	84	(84)(H)	—
Prepayments and Other	78		78
TOTAL CURRENT ASSETS	1,390	(84)	1,306
DEFERRED CHARGES AND OTHER ASSETS:			
Deferred Plant Costs	503	(503)(H)	—
Mirror CWIP Asset	285	(285)(H)	—
Other Non-Utility Investments	448	(448)(E)	—
Securities Available for Sale	103	(103)(F)	—
Income Tax Related Regulatory Assets, Net	329	(329)(H)	—
Goodwill	1,428		1,428
Regulatory Assets	—	1,440 (H)	1,440
Other Deferred Charges	337	(239)(H)	98
TOTAL DEFERRED CHARGES AND OTHER ASSETS	3,433	(467)	2,966
TOTAL	$13,451	$ —	$13,451

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

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CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED BALANCE SHEET

December 31, 1997

(in millions)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION:			
Common Stock	$ 743		$ 743
Paid-in Capital	1,039		1,039
Retained Earnings	1,746	$ 28 (I)	1,774
Foreign Currency Translation Adjustment and Other	28	(28)(I)	—
Total Common Shareholders' Equity	3,556	—	3,556
Cumulative Preferred Stocks of Subsidiaries:			
Not Subject to Mandatory Redemption	176		176
Subject to Mandatory Redemption	26		26
Certain Subsidiary-obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	335		335
Long-term Debt	3,898		3,898
TOTAL CAPITALIZATION	7,991	—	7,991
OTHER NONCURRENT LIABILITIES	—	27 (J,K)	27
CURRENT LIABILITIES:			
Preferred Stock and Long-term Debt Due Within One Year	32		32
Short-term Debt	721	692 (L)	1,413
Short-term Debt—CSW Credit, Inc.	636	(636)(L)	—
Loan Notes	56	(56)(L)	—
Accounts Payable	558		558
Taxes Accrued	171		171
Interest Accrued	87		87
Obligations Under Capital Leases	—	2 (J)	2
Other	238	(2)(J)	236
TOTAL CURRENT LIABILITIES	2,499	—	2,499
DEFERRED INCOME TAXES	2,432		2,432
DEFERRED INVESTMENT TAX CREDITS	278		278
DEFERRED CREDITS	251	(27)(J,K)	224
TOTAL	$13,451	$ —	$13,451

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Notes to Unaudited Pro Forma Combined Condensed Financial Statements

1. There were no material intercompany transactions between AEP, including its subsidiaries, and CSW, including its subsidiaries, during the periods presented.

2. The unaudited pro forma combined condensed financial statements reflect the conversion of each outstanding CSW Share into 0.60 of an AEP Share, as provided in the Merger Agreement. The unaudited pro forma combined condensed financial statements are presented as if the companies were combined during all periods included therein. The combined authorized shares reflect the number of shares which would be authorized assuming the Share Issuance proposed herein had been approved on December 31, 1997.

3. The principal accounting policies for both companies' regulated operations are to follow the methods used by their respective regulatory commissions in establishing rates. The consummation of the Merger is not expected to result in any changes in the way regulators treat allowable costs for rate-making purposes. The effects of accounting policy differences are immaterial and have not been adjusted in the pro forma combined condensed financial statements.

4. The pro forma average number of outstanding AEP Shares was calculated by multiplying the average number of outstanding CSW Shares during the year by the exchange ratio of 0.60 of an AEP Share and adding the result to the average number of outstanding AEP Shares during the year.

5. The pro forma adjustment to common stock and paid-in capital represents the effects of recording the Merger of AEP and CSW as of the consummation date using the pooling of interests method of accounting whereby the common stock and paid-in capital amounts are adjusted to reflect the difference in par value ($6.50 per AEP Share compared with $3.50 per CSW Share) and the exchange ratio of 0.60 of an AEP Share for each CSW Share.

6. In connection with the Merger, the companies expect to incur charges estimated at approximately $50 million for transaction costs. Such costs include investment banking (financial advisors), legal, accounting, filing, printing and other related fees and costs to consummate the Merger. The combined company intends to seek recovery of the transaction costs through the regulatory process. The pro forma combined condensed financial statements do not reflect any of the costs savings estimated to result from the merger or any cost to achieve the merger. As noted in the "Reasons for the Merger" section, a sharing of the cost savings, net of the costs to achieve the Merger, is expected to be the outcome of the various regulatory proceedings. See "Reasons for the Merger" for further discussion regarding estimated synergies and cost savings (page 42).

7. The CSW unaudited reclassifying condensed financial statements reflect the reclassifying entries necessary to adjust CSW's condensed balance sheet and condensed statement of income presentation to be consistent with the presentation expected to be used by AEP after the Merger is completed. The following describes such reclassifying entries:

Statements of Income Reclassifying Entries

(A) To reclassify other diversified income and expenses to nonoperating income.

(B) To reclassify state and United Kingdom income taxes.

Balance Sheets Reclassifying Entries

(C) To reclassify nuclear fuel.

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(D) To reclassify non-utility plant and related accumulated depreciation.

(E) To reclassify other non-utility investments.

(F) To reclassify securities available for sale.

(G) To reclassify accrued utility revenues.

(H) To reclassify regulatory assets.

(I) To reclassify foreign currency translation and other.

(J) To reclassify obligations under capital leases.

(K) To reclassify operating reserves.

(L) To reclassify short-term debt.

DESCRIPTION OF CAPITAL STOCK OF AEP

The following statements are brief summaries of certain provisions relating to AEP's capital stock and are qualified in their entirety by reference to the provisions of the AEP Charter and AEP's By-Laws (the "AEP Bylaws"), which are incorporated by reference as an exhibit to the registration statement on Form S-4 filed with the SEC by AEP (the "Registration Statement") of which this Joint Proxy Statement/ Prospectus is a part.

AEP's authorized capitalization presently consists of 300,000,000 AEP Shares, of which 190,378,571 shares were issued and outstanding as of April 8, 1998.

Dividend Rights

Dividends may be declared and paid on the AEP Shares out of legally available surplus.

Voting Rights

The holders of AEP Shares have exclusive voting rights of one vote for each share held. The holders of AEP Shares are entitled to cumulative voting in the election of directors.

Liquidation Rights

In the event of any liquidation of AEP, the holders of AEP Shares are entitled to share ratably in the remaining assets of AEP available for distribution.

Preemptive Rights

The holders of AEP Shares, upon the issuance for money or other consideration of any stock or any securities convertible into any stock, shall not have any preemptive right unless the AEP Board of Directors determine to issue and sell AEP Shares solely for money and other than by (i) a public offering, (ii) an offering to or through underwriters or dealers who agree to make a public offering, or (iii) any other offering which is authorized or approved by the affirmative vote of the outstanding AEP Shares.

Transfer Agents and Registrars

The transfer agent and registrar for the AEP Shares is First Chicago Trust Company of New York.

COMPARISON OF RIGHTS OF HOLDERS OF CSW SHARES AND AEP SHARES

General

As a result of the Merger, holders of CSW Shares will become shareholders of AEP, and the rights of such former CSW stockholders will thereafter be governed by the AEP Charter and the AEP Bylaws and the laws of the State of New York. The rights of the holders of CSW Shares are currently governed by the Second Restated Certificate of Incorporation of CSW (the "CSW Charter") and the Bylaws of CSW, as amended (the "CSW Bylaws") and the laws of the State of Delaware. The following summary sets forth the material differences between the AEP Charter and the CSW Charter, the AEP Bylaws and the CSW Bylaws, and New York and Delaware law. This summary is qualified in its entirety by reference to the full text of each of such documents and the applicable state statutes. For information as to how such documents may be obtained, see "WHERE YOU CAN FIND MORE INFORMATION".

Shareholder Rights Plans

AEP has no shareholder rights plan.

CSW has a stockholder rights plan (the "CSW Rights Agreement") which provides that after a person or group acquires or announces a tender or exchange offer to acquire 15% or more of the outstanding CSW Shares, the holder of a CSW Share (other than the Acquiring Person) is entitled to purchase, at the exercise price, additional CSW Shares having a current market value of two times the exercise price (a "CSW Right"). In addition, if CSW is acquired in a merger or other business combination, each CSW Right will entitle the holder to purchase, at the exercise price, common stock of the acquiror having a current market value of two times the exercise price.

The Merger Agreement provides that CSW shall take, and CSW has taken, actions (including amending the CSW Rights Agreement) so that the execution, delivery and performance of the Merger Agreement and the consummation of the Merger and other transactions contemplated thereby, will not result in the grant of any CSW Right or enable or require that any outstanding CSW Rights be exercised, distributed or triggered.

Voting Rights

Generally

Each holder of CSW Shares is entitled to one vote for each share held by such holder upon each matter voted upon. In the election of directors, the principle of cumulative voting does not apply. Votes may, in all cases, be cast by proxy, but no stockholder can designate more than three persons as proxies. The affirmative vote of a majority of the CSW Shares represented at a meeting shall be the act of the stockholders, unless a greater number is required by law.

Every holder of record of AEP Shares has one vote for each share held for the election of directors and upon all other matters; provided, however, that at all elections of directors, cumulative voting shall apply.

Election of Directors

The CSW Charter provides that directors shall be divided into three classes as nearly equal in size as is practicable. The directors shall hold office for three years. The CSW Charter provides that the number of directors should be not less than nine nor more than fifteen, as may be fixed from time to time by the resolutions adopted by a majority of the entire CSW Board of Directors. The number of directors at CSW is currently fixed at 12. The CSW Bylaws provide that, except with respect to persons who were serving as directors on October 12, 1987, and who were 60 years old or over at such time, the CSW Board of Directors shall not elect nor propose for election (a) any non-employee who is 70 years old or will be 70 years old on or before the date of the election, or (b) any employee of CSW or any of its subsidiaries (other than any past or present Chief Executive Officer of CSW) whose service as such employee has terminated or will in normal course terminate on or before the date of election. In addition, the CSW Bylaws provide that the term of any director who is an employee of CSW or any of its subsidiaries, (other than a Chief Executive Officer who retires) shall expire concurrently with the termination of service of that director as an employee.

The AEP Bylaws provide that the number of directors shall be not less than nine nor more than seventeen. Each director will hold office until the next annual meeting. The number of directors shall be the number fixed by resolution of the AEP Board of Directors. The number of directors of AEP is currently fixed at 13. Upon consummation of the Merger, the number of directors of AEP will be fixed at 15.

Approval of Certain Transactions

The DGCL generally requires the affirmative vote of a majority of the outstanding stock entitled to vote thereon for the approval of any merger or consolidation. Unless required by the certificate of incorporation, no stockholder approval is required for certain mergers in which (i) there is no amendment to the certificate of incorporation of a corporation, (ii) each share of stock of such corporation is to be an identical outstanding or treasury share of the surviving corporation after the effective date of the merger and (iii) either no stock or shares, securities or obligations convertible into such stock, will be issued or delivered in connection with the merger or the unissued shares or treasury shares of stock to be issued or delivered in connection with the merger plus those initially issuable upon any conversion of any other shares, securities or obligations to be issued or delivered under such plan are less than 20% of the shares of common stock of such corporation outstanding immediately prior to the effective date of the merger.

The New York Business Corporation Law (the "NYBCL") requires for corporations in existence on February 23, 1998 the certificate of incorporation of which does not expressly provide for approval of a Merger or consolidation by a majority vote of the outstanding shares entitled to vote thereon, the affirmative vote of two-thirds of all outstanding shares entitled to vote thereon to effect a merger, a consolidation, a share exchange or the sale, lease or disposition of all or substantially all of a corporation's assets. Notwithstanding any provision in the certificate of incorporation, the holders of shares of a class or series are entitled to vote as a class if such shares will remain outstanding after the merger or will be converted into the right to receive shares of stock of the surviving or consolidated corporation or another corporation and the certificate or articles of incorporation of the surviving or consolidated corporation or of such other corporation immediately after the effectiveness of the merger or consolidation would contain any provision which is not contained in the certificate of incorporation of the corporation and which, if contained in an amendment to the certificate of incorporation, would entitle the holders of shares of such class or such one or more series to vote and to vote as a separate class thereon. The NYBCL does not contain a provision for mergers (other than those between a corporation and its 90% or more owned subsidiary) without the approval of shareholders similar to that in the DGCL.

Since the Merger is to be effected between Sub and CSW, both Delaware corporations, (and AEP is not a constituent corporation in the Merger) the approval procedure described in the preceding paragraph does not apply to AEP with respect to the Merger.

Fair Price Provisions

The CSW Charter contains a "fair price" provision that applies to certain business combination transactions involving (i) any person that beneficially owns 5% or more of the voting power of all of the outstanding stock of CSW or (ii) any affiliate (as defined in the CSW Charter) or associate (as defined in the CSW Charter) of CSW that during the previous two year period was the beneficial owner of 5% or more of the voting power of all of the outstanding stock of CSW (a "CSW Interested Stockholder"). The "fair price" provision requires (i) the affirmative vote of the holders of at least 80% of the outstanding voting stock of CSW and (ii) the affirmative vote of a majority of the outstanding voting stock of CSW held by persons other than the CSW Interested Stockholder to approve certain transactions between CSW and the CSW Interested Stockholder. These transactions include any merger or consolidation of CSW or its subsidiaries, any sale, lease, exchange, mortgage, pledge, transfer or other disposition of the assets of CSW having a fair market value in excess of $25 million, any adoption of a plan or proposal of termination, liquidation or dissolution of CSW, any reclassification of securities or recapitalizations of CSW, certain issuances or transfers of CSW securities, and certain other transactions involving the CSW Interested Stockholder. The voting requirement does not apply to certain transactions, including those that are approved by CSW's Continuing Directors (as defined in the CSW Charter) or that meet certain "fair price" criteria contained in the CSW Charter. **The CSW Board approved the merger at its December 21, 1997 meeting, thus the above described voting requirement does not apply to the vote to approve and adopt the Merger.**

The AEP Charter contains a "fair price" provision that applies to certain business combinations or transactions involving (i) any person that beneficially owns more than 5% of the combined voting power of the then outstanding voting stock of AEP, (ii) any affiliate (as defined in the AEP Charter) of AEP that within the five-year period immediately prior to the date in question, beneficially owned more than 5% of the combined voting power of the outstanding voting stock of AEP (each of the shareholders described in clauses (i) and (ii) being referred to as "AEP Interested Stockholders"), or (iii) an assignee of or one who otherwise succeeded to any shares of voting stock which were during the prior five-year period beneficially owned by an AEP Interested Stockholder, provided that the transaction to which such assignment occurred was not a public offering. The "fair price" provision requires the affirmative vote of (i) at least 75% of the combined voting power of the then issued and outstanding voting stock of AEP, and (ii) a majority of the combined voting power of the then issued and outstanding voting stock beneficially owned by persons other than such AEP Interested Stockholder to approve certain transactions between AEP and the AEP Interested Stockholder. These transactions include any merger or consolidation of AEP or any subsidiary with the AEP Interested Stockholder or any other corporation which is or would be an affiliate of an AEP Interested Stockholder, any sale, lease, license, exchange, mortgage, pledge, transfer or other disposition of the assets of AEP having a fair market value of more than $100 million to or with any AEP Interested Stockholder, the issuance or transfer by AEP or any subsidiary of any securities of AEP or a subsidiary having a fair market value of more than $100 million to any AEP Interested Stockholder or any affiliate, the adoption of any plan for the liquidation or dissolution of AEP proposed by or on behalf of the AEP Interested Stockholder or any affiliate, or any reclassification of securities, recapitalization or reorganization of AEP, or any merger or consolidation of AEP with any of its subsidiaries, or any self tender offer for or repurchase which has the effect of increasing the proportionate share of outstanding shares owned by any AEP Interested Stockholder or any affiliate. The voting requirement does not apply to certain transactions, including those that are approved by a majority of AEP's Disinterested Directors (as defined in the AEP Charter) or that meet certain "fair price" criteria contained in the AEP Charter.

Amendments to Certificate of Incorporation

Under both Delaware and New York law, amendments to a certificate of incorporation may be authorized by the vote of the holders of a majority of all outstanding shares entitled to vote thereon. Both states also provide for approval by vote of the holders of a majority of outstanding shares of a particular class of stock in certain circumstances.

Special Meetings

Under both Delaware and New York law, special meetings of stockholders may be called by the board of directors and by such other person or persons authorized to do so by the corporation's certificate of incorporation or bylaws. In addition, Delaware law provides that, if an annual meeting is not held or an action by written consent to elect directors in lieu of an annual meeting is not taken within 30 days of the date designated for such a meeting, or is not held for a period of 13 months after the latest to occur of the organization of the corporation, its last annual meeting or the last action by written consent to elect directors in lieu of an annual meeting, the Delaware Court of Chancery may summarily order a meeting to be held upon the application of any stockholder or director. Under New York law, if there is a failure to elect a sufficient number of directors to conduct the business of the corporation for a period of one month after the date fixed by or under the bylaws for the annual meeting of stockholders or for a period of 13 months after the last annual meeting, the board of directors may call a special meeting for the election of directors. If the board fails to do so within 2 weeks, holders of 10% of the votes of the shares entitled to vote in an election of directors may demand the call of a special meeting for an election of directors.

The CSW Bylaws provide that special meetings of the stockholders of CSW may be called by the Chairman, by the CSW Board of Directors, by a majority of the CSW Directors individually or by holders of not less than one-third of the total outstanding shares of stock. Such special meeting shall be held at such place, date and hour as may be fixed by the person or persons calling the meeting. Special meetings of the shareholders of AEP may be called by the AEP Board of Directors or the AEP Executive Committee, or of stockholders holding one-fourth of the capital stock, at such time and at such place as may be stated in the call and notice.

Shareholders' Action Without a Meeting

The DGCL provides that unless otherwise provided in the certificate of incorporation, stockholders may take any action without a meeting by written consent signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Prompt notice of the taking of any action by less than unanimous consent must be given to stockholders who did not consent to such action and who, if the action had taken place at a meeting, would have been entitled to notice.

The NYBCL provides that shareholders may take any action without a meeting by written consent only if such consent is signed by the holders of all outstanding shares entitled to vote thereon or, if the certificate of incorporation so permits, the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Prompt notice of the corporate action without a meeting by less than unanimous consent shall be given to those stockholders who have not consented in writing.

Neither the AEP Charter nor the CSW Charter contains any provision altering these provisions of the statutes.

Preemptive Rights

For corporations incorporated after July 3, 1967, Delaware law does not provide for preemptive rights to the holders of capital stock unless the certificate of incorporation provides for such rights. The CSW Charter provides that any shares of common stock may be issued without first being offered to stockholders.

The NYBCL provides, for corporations incorporated before February 23, 1998, subject to certain exceptions, preemptive rights to shareholders upon an issuance of securities which would adversely affect certain specified interests of such shareholders, provided that the certificate of incorporation may provide otherwise. The AEP Charter provides that subject to certain exceptions, upon any issuance for money or other consideration of any stock, no holder of stock of any kind shall have any preemptive rights. Under the exceptions to the AEP Charter, preemptive rights are available where AEP issues or sells any shares solely for money and other than by a public offering, an offering to or through underwriters or dealers who agree to make a public offering or any offering which is authorized by the shareholders.

Dividends

Subject to any restrictions in a corporation's certificate of incorporation (which restrictions the CSW Charter does not include), the DGCL generally provides that the directors of a corporation may declare and pay dividends only out of surplus (defined as the excess if any, of the net assets over capital) or, when no surplus exists, out of net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. Dividends may not be paid out of net profits if the capital of the corporation is less than the aggregate amount of capital represented by the issued and outstanding stock of all classes having a preference upon the distribution of assets.

Under the NYBCL, a corporation may declare and pay dividends on its outstanding shares except when currently the corporation is insolvent or would thereby be made insolvent, or when the declaration, payment or distribution would be contrary to any restrictions contained in the certificate of incorporation (which restrictions the AEP Charter does not include). In general, dividends may be declared or paid out of surplus only.

Stock Repurchases

The DGCL permits a corporation to repurchase or redeem its shares, except that a corporation may not do so when the capital of the corporation is impaired or when such purchase or redemption would cause any impairment of the capital of the corporation. A purchase or redemption out of capital of shares which are entitled upon any distribution of the corporation's assets, whether by dividend or liquidation, to a preference over another class or series of its stock, or, if no shares entitled to such preference are outstanding, any of its own shares, is permitted if such shares will be retired upon their acquisition and the capital of the corporation reduced in accordance with Delaware law.

Under the NYBCL, notwithstanding any authority contained in the certificate of incorporation, the shares of a corporation may not be purchased, redeemed, converted or exchanged, if the corporation is then insolvent or would thereby be made insolvent. Shares may be purchased or redeemed only out of surplus.

Issuance of Rights or Options to Purchase Shares to Directors, Officers and Employees

The DGCL permits any corporation, subject to any provisions in its certificate of incorporation, to create rights or options entitling the holders thereof to purchase from the corporation any shares of its capital stock of any class or classes. The terms shall be stated in the certificate of incorporation or in a resolution adopted by the board of directors. The DGCL provides that, in the absence of actual fraud in the transaction, the judgment of the directors as to the consideration for the issuance of such rights or options and the sufficiency thereof shall be conclusive. This provision has been interpreted by Delaware case law not to apply to interested director transactions or to issuances that constitute waste. The NYBCL requires that the issuance to officers, directors or employees of rights or options to purchase shares must be authorized by a majority of votes cast at a meeting of shareholders, or authorized by and consistent with a plan adopted by such vote of shareholders. In the absence of preemptive rights, such authorization is not required in New York for the issuance of rights or options in substitution for or upon the assumption of rights or options of a corporation with which the issuing corporation is merging or consolidating.

Loans to Directors

The DGCL permits any corporation to lend money to, or guarantee an obligation of, or otherwise assist any officer or other employee of the corporation or of its subsidiary, including any officer or employee who is a director of the corporation or its subsidiary, whenever, in the judgment of the directors, such loan, guaranty or assistance may reasonably be expected to benefit the corporation.

Under the NYBCL, a corporation may not lend money to or guarantee the obligations of a director of the corporation unless either the particular loan or guarantee is approved by the shareholders, or the certificate of incorporation expressly permits such transactions. The AEP Charter does not contain any such provision.

Classification of the Boards of Directors

Both the DGCL and the NYBCL provide that a corporation's board of directors may be divided into various classes with staggered terms of offices. Neither the AEP Charter nor the AEP Bylaws provide for a classified board. Both the CSW Charter and the CSW Bylaws provide for three classes of directors, as nearly equal in size as practicable. Under the DGCL, unless otherwise provided in a corporation's certificate of incorporation, directors of a corporation with a classified board may only be removed by stockholders of the corporation for cause. CSW's Charter does not override the DGCL provision regarding removal of classified directors.

Duties of Directors

The NYBCL specifically permits a board of directors to consider constituencies other than the holders of a corporation's capital stock and to consider both the long-term and short-term interests of the corporation and such constituencies when taking any action, including action taken in connection with a change or potential change in the control of the corporation. The NYBCL permits directors to consider the effect that a corporation's actions may have in the short-term and the long-term upon (i) potential growth, development, productivity and profitability of the corporation; (ii) current employees; (iii) retired employees and other beneficiaries receiving or entitled to receive retirement, welfare or similar benefits from the corporation; (iv) the corporation's customers and creditors; and (v) the ability of the corporation to provide continuously goods, services, employment opportunities and employment benefits and make other contributions to the communities in which it does business. The DGCL contains no similar provision; however, Delaware case law has established that, in connection with a potential change of control of a corporation, its directors may consider, among various other proper factors, the impact of both the bid and the potential acquisition on constituencies other than stockholders, but only to the extent that they are rationally related to the benefits from the change of control that would accrue to the stockholders.

Limitations on Directors' Liability

The DGCL permits a corporation to include a provision in its certificate of incorporation eliminating or limiting the personal liability of a director to the corporation or its stockholders for damages for breach of the director's fiduciary duties. This limitation is unavailable for (i) breaches of the director's duty of loyalty, (ii) acts or omissions not in good faith or which involved intentional misconduct or knowing violation of the law (iii) unlawful payment of dividends, or unlawful stock purchases; or (iv) any transaction from which the director derived an improper personal benefit. The CSW Charter includes such a provision to the full extent permitted by law.

The NYBCL permits a corporation to limit or eliminate a director's personal liability to the corporation or the holders of its capital stock for breach of duty. This limitation is generally unavailable for acts or omissions by a director which were (i) in bad faith, (ii) involved intentional misconduct or a knowing violation of law or (iii) involved a financial profit or other advantage to which such director was not legally entitled. The NYBCL also prohibits limitations on director liability for acts or omissions which resulted in a violation of a statute prohibiting certain dividend declarations, certain share repurchases or redemptions, certain payments to shareholders after dissolution and particular types of loans.

The AEP Charter provides for limitations on directors' liability to the fullest extent permitted by the NYBCL.

Indemnification of Directors and Officers

The DGCL permits a corporation to indemnify officers, directors, employees and agents for actions taken in good faith and in a manner they reasonably believed to be in, or not opposed to, the best interests of the corporation, and with respect to any criminal action, which they had no reasonable cause to believe was unlawful. The DGCL also provides that a corporation may advance expenses of defense (upon receipt of an undertaking to reimburse the corporation if indemnification is not appropriate) and must reimburse a successful defendant for expenses, including attorney's fees, actually and reasonably incurred, and permits a corporation to purchase and maintain liability insurance for its directors and officers. The DGCL further provides that indemnification may not be made for any claim, issue or matter as to which a person has been adjudged by a court of competent jurisdiction, after exhaustion of all appeals therefrom, to be liable to the corporation, except only to the extent a court determines that the person is entitled to indemnity for such expenses that such court deems proper.

The CSW Bylaws provide that each person who is or was or had agreed to become a director or officer, or each such person who is or was serving or had agreed to serve at the request of the CSW Board of Directors or an officer as an employee or agent or as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise (including the heirs, executors, administrators or estate of such person), shall be indemnified (including, without limitation, the advancement of expenses and payment of all loss, liability and expenses) to the full extent permitted by the law as presently in effect or as may hereafter be amended (but in the case of any such amendment, only to the extent that such amendment permits broader indemnification rights than said laws permitted prior to such amendment); provided, however, that no person shall be indemnified for amounts paid in settlement unless the terms and conditions of such settlement have been consented to by CSW and provided further, that no indemnification for employees or agents (other than directors and officers) will be made without the express authorization of the CSW Board of Directors.

Under the NYBCL, a corporation may indemnify any person made, or threatened to be made, a party to an action or proceeding (other than one by or in the right of the corporation to procure a judgment in its favor), whether civil or criminal, including an action by or in the right of any other corporation of any type or kind, domestic or foreign, or any partnership, joint venture, trust, employee benefit plan or other enterprise, which any director or officer of the corporation served in any capacity at the request of the corporation, by any reason of the fact that he, his testator or intestate, was a director or officer of the corporation, or served such other corporation, partnership, joint venture, trust, employee benefit plan or other enterprise in any capacity, against judgments, fines, amounts paid in settlement and reasonable expenses, including attorneys' fees actually and necessarily incurred as a result of such action or proceeding, or any appeal therein, if such director or officer acted, in good faith, for a purpose which he reasonably believed to be in, or, in the case of service for any other corporation or any partnership, joint venture, trust, employee benefit plan or other enterprise, not opposed to, the best interests of the corporation and, in criminal actions or proceedings, in addition, had no reasonable cause to believe that his conduct was unlawful.

The NYBCL further provides that no indemnification of directors in shareholder derivative suits may be made in respect of (i) a threatened action, or a pending action which is settled or otherwise disposed of, or (ii) any claim, issue or matter as to which the director or officer has been adjudged to be liable to the corporation, unless and only to the extent that the court in which the action was brought or, if no action is brought, any court of competent jurisdiction, determines upon application that, in view of the circumstances of the case, the director or officer is fairly and reasonably entitled to indemnity for such portion of the settlement amount and expenses as the court deems proper. The statutory provisions for indemnification and advancement of expenses are not exclusive of any other rights to which those seeking indemnification or advancement of expenses may be entitled independently of the applicable statutory provision.

The AEP Bylaws provide that to the fullest extent permitted by law, AEP shall indemnify any person made, or threatened to be made, a party to any action or proceeding (formal or informal), whether civil, criminal, administrative or investigative and whether by or in the right of AEP or otherwise, by reason of the fact that such person, such person's testator or intestate, is or was a director, officer or employee of AEP, or of any subsidiary or affiliate of AEP, or served any other corporation, partnership, joint venture, trust, employee benefit plan or other enterprise in any capacity at the request of AEP, against all loss and expense including, without limiting the generality of the foregoing, judgments, fines (including excise taxes), amounts paid in settlement and attorneys' fees and disbursements actually and necessarily incurred as a result of such action or proceeding, or any appeal therefrom, and all legal fees and expenses incurred in successfully asserting a claim for indemnification pursuant to such provision of the AEP Bylaws; provided, however, that no indemnification may be made to or on behalf of any director, officer or employee if a judgment or other final adjudication adverse to the director, officer or employee establishes that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled.

The AEP Bylaws further provide that in any case in which a director, officer or employee (or a representative of the estate of such director, officer or employee) requests indemnification, upon such person's request the AEP Board of Directors shall meet within sixty days thereof to determine whether such person is eligible for indemnification in accordance with the standard set forth above. Such a person claiming indemnification shall be entitled to indemnification upon a determination that no judgment or other final adjudication adverse to such person has established that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled.

Removal of Directors

Under the DGCL, directors may be removed, with or without cause, by the vote of a majority of the outstanding shares of all classes of stock entitled to vote present at a meeting of stockholders. The DGCL imposes additional restrictions on the removal of directors for corporations with cumulative voting or directors elected by the holders of a specific class or series of shares. Unless the certificate of incorporation otherwise provides, in the case of a corporation with a classified board, stockholders may effect such removal only for cause. The CSW Charter provides that a director may be removed only for cause and only by the affirmative vote of the holders of eighty percent of the CSW Shares.

The NYBCL provides that any or all of the directors of a corporation may be removed for cause by a vote of the shareholders and that the certificate of incorporation or bylaws may provide for removal without cause by vote of the shareholders. Under the statute, subject to certain exceptions, directors may also be removed without cause by action of the board if such is provided for in the certificate of incorporation or the bylaws. The AEP Charter and the AEP Bylaws contain no provision for removal of directors without cause by the shareholders or the board. The NYBCL also imposes additional restrictions on the removal of directors of corporations with cumulative voting or directors elected by the holders of a specific class or series of shares. For corporations having cumulative voting, no director may be removed when the votes cast against his or her removal would be sufficient to elect him or her if voted cumulatively at an election at which the same total number of votes were cast and the entire board, or the entire class of directors of which he or she is a member, were then being elected.

Newly Created Directorships and Vacancies

Delaware law provides that, unless otherwise provided in the certificate of incorporation or bylaws, vacancies, including those due to removal without cause, and newly created directorships may be filled by majority vote of the directors then in office, even if the number of directors then in office is less than a quorum. If, at the time of filling any vacancy or newly created directorship, the directors then in office constitute less than a majority of the whole board, the Court of Chancery has the authority, upon application of stockholders holding at least 10% of the shares outstanding at the time and entitled to vote, to order an election to be held to fill any such vacancies or new directorships, or to replace the directors chosen by the directors then in office.

New York law provides that newly created directorships and vacancies occurring for any reason other than removal without cause (which the AEP Charter does not currently permit), may be filled by vote of the board of directors. If the number of directors then in office is less than a quorum, any newly created directorships and vacancies may be filled by vote of a majority of the directors then in office. Under the AEP Bylaws, vacancies in the board may be filled by the board at any meeting.

Dissenters' Rights of Appraisal

In certain circumstances, Section 262 of the DGCL entitles a stockholder to exercise its appraisal rights upon a merger or consolidation of the corporation effected pursuant to the DGCL if the holder complies with the requirements of Section 262 thereof. Appraisal rights are available under Section 262 of the DGCL if holders of shares in a constituent company which shares are listed on a national securities exchange are required by the terms of the merger to accept consideration other than shares of stock of the surviving corporation, shares of stock of any corporation listed on a national securities exchange, designated as a national market system security on an interdealer quotation system by the National Association of Securities Dealers, Inc. or held of record by more than 2,000 stockholders or cash in lieu of fractional shares.

Stockholders of CSW are not entitled to appraisal rights under the DGCL in connection with the Merger because AEP Shares are listed on the NYSE and holders of CSW Shares are not required upon consummation of the Merger to exchange such shares for any consideration other than AEP Shares or cash in lieu of fractional shares.

The NYBCL grants dissenters' rights to shareholders (i.e., the right to cash payment of the fair value of one's shares determined by judicial appraisal) in the case of a merger or consolidation, a sale, lease, exchange or other disposition of all or substantially all of the corporation's assets, any share exchange in which the corporation is participating as a subject corporation (but only those shareholders whose shares have been acquired), and (in the case of a shareholder whose shares are adversely affected thereby) certain amendments to the certificate of incorporation, as the case may be. The NYBCL provides that dissenters' rights are not available to a shareholder in a merger or consolidation that receives shares that are listed on a national securities exchange or designated as a national market system security. The NYBCL, in determining the "fair value" for payment of shares, mandates that the court consider the nature of the transaction and its effect on the corporation and its shareholders, and the concepts and methods of valuation then customary in the relevant financial and securities markets.

AEP shareholders are not entitled to appraisal rights under the NYBCL in connection with the Merger, because they are retaining their AEP Shares and the Charter Amendment does not cause the AEP shareholders to be adversely affected.

Business Combination Statutes

In 1988, Delaware enacted a statute designed to provide Delaware corporations with limited protection against hostile takeovers. The takeover statute, which is codified in Section 203 of the DGCL ("Section 203"), in general, provides that a person or entity that owns 15% or more of the outstanding voting stock of a Delaware corporation (an "Interested Stockholder") may not consummate a merger or other business combination transaction with such corporation at any time during the three-year period following the date such person or entity became an Interested Stockholder, unless an exemption described below is applicable. The term "business combination" is defined broadly to cover a wide range of corporate transactions including mergers, sales of assets, issuances of stock, transactions with subsidiaries and the receipt of disproportionate financial benefits.

The statute exempts the following transactions from the requirements of Section 203: (i) any business combination if, prior to the time a person became an Interested Stockholder, the board of directors approved either the business combination or the transaction which resulted in the stockholder becoming an Interested Stockholder, (ii) any business combination involving a person who acquired at least 85% of the outstanding voting stock in the transaction in which he or she became an Interested Stockholder, with the number of shares outstanding calculated without regard to those shares owned by the corporation's directors who are also officers or by certain employee stock plans, and (iii) any business combination with an Interested Stockholder that is approved by the board of directors and by a two-thirds vote of the outstanding voting stock not owned by the Interested Stockholder. The CSW Charter does not contain an election, as permitted by Delaware law, to be exempt from the requirements of Section 203.

Under Section 912 of the NYBCL ("Section 912"), a corporation is generally prohibited from engaging in certain business combinations (as defined by the statute to include certain mergers and consolidations, dispositions of assets and issuances of securities, as well as certain other transactions) with an interested stockholder (as defined by the statute generally to include holders of 20% or more of the outstanding stock of the corporation) for a period of five years following the date that such stockholder became an interested stockholder, unless certain exemptions, including the business combination or the purchase of stock by means of which the interested shareholder became such is approved by the corporation's board of directors in advance of such stock purchase, or unless the interested shareholder was the beneficial owner of 5% or more of the corporation's outstanding voting stock on October 30, 1985, and remains so until becoming an interested shareholder.

Neither Section 203 nor Section 912 are applicable to the Merger and the transactions contemplated by the Merger Agreement.

"Anti-Greenmail"

The NYBCL provides that no domestic corporation may purchase or agree to purchase more than 10% of its stock from a shareholder who has held the shares for less than two years at any price which is higher than the market price unless such transaction is approved by both the corporation's board of directors and a majority of the votes of all outstanding shares entitled to vote thereon at a meeting of shareholders unless the certificate of incorporation requires a greater percentage or the corporation offers to purchase shares from all the holders on the same terms. The DGCL contains no similar provision.

Stock Exchange *Listings*

CSW Shares are listed on the NYSE and Chicago Stock Exchange. AEP Shares are listed on the NYSE.

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Order Dated April 22, 1999
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THE MERGER AGREEMENT

The following is a brief summary of the material provisions of the Merger Agreement, which appears as Annex I to this Joint Proxy Statement/Prospectus and is incorporated herein by reference. Such summary is qualified in its entirety by reference to the Merger Agreement.

The Merger

The Merger Agreement provides that, following the approval and adoption of the Merger Agreement by the holders of CSW Shares and the approval of certain related matters by the holders of AEP Shares and the satisfaction or waiver of the other conditions to the Merger, Sub will be merged with and into CSW, and CSW will continue as the Surviving Corporation and CSW will be a wholly-owned subsidiary of AEP.

If the conditions to the Merger are satisfied or waived, the parties will file with the Secretary of State of the State of Delaware a duly executed certificate of merger, and the Merger will become effective upon the filing and acceptance thereof or at such date thereafter as is provided in the certificate of merger.

CSW Shares outstanding at the Effective Time will be converted into AEP Shares, as described under "THE MERGER — Merger Consideration". With regard to the treatment of fractional share interests, see "THE MERGER — Fractional Shares".

Representations and Warranties

The Merger Agreement contains various representations and warranties of each of CSW and AEP relating to, among other things, (i) its organization and similar corporate matters; (ii) its capitalization; (iii) the authorization, execution, delivery, performance and enforceability of the Merger Agreement; (iv) the specification of the permits and orders required from governmental authorities for the execution, delivery and performance of the Merger Agreement; (v) the absence of conflicts, violations and defaults under any law, regulations or order, its charter and bylaws and certain other agreements and documents with respect to its execution, delivery and performance of the Merger Agreement; (vi) the documents and reports filed by it with the SEC and other governmental authorities and the accuracy of the information, including the financial statements, contained therein; (vii) the absence of certain changes and events; (viii) the material permits and orders from governmental authorities required to conduct its business, including its nuclear facilities; (ix) its litigation and compliance with laws; (x) its ownership of common stock of the other party; (xi) employee benefit plans, (xii) its taxes, (xiii) certain environmental matters, (xiv) its affiliates; (xvii) the opinion of its financial advisor; (xviii) its brokers or investment bankers involved in the transactions; and (xix) the vote required of its stockholders to consummate the Merger. The representations and warranties of CSW and AEP also extend in many respects to their respective subsidiaries and, in the case of AEP, Sub joins in the representations and warranties of AEP. The representations and warranties expire at the Effective Time.

Certain Covenants; Conduct of Business Prior to the Merger

Business Maintenance. Each of CSW and AEP has agreed that, prior to the Effective Time, unless expressly contemplated by the Merger Agreement or otherwise consented to in writing by the other, it will and will cause its subsidiaries (i) to operate its business in the usual and ordinary course consistent with past or then current industry practices; (ii) to use all commercially reasonable efforts to preserve substantially intact its business organization, to maintain its rights and franchises, to retain the services of its respective key employees and to maintain its relationships with its respective customers and suppliers; (iii) to maintain and keep its properties and assets in as good repair and condition as at present, ordinary wear and tear excepted, and to maintain supplies and inventories in quantities consistent with its customary business practice; and (iv) to use all commercially reasonable efforts to keep in full force and effect insurance and bonds comparable in amount and scope of coverage to that currently maintained; (v) to use all commercially reasonable efforts to maintain in effect all existing orders and permits relating to its operations and timely to apply for any additional orders and permits that are or will be required for its current or currently planned operations; and (vi) to consult with each other on a frequent and reasonable basis in order to ensure compliance with the covenants in the Merger Agreement and otherwise as necessary to consummate the Merger (subject to retention of discretion and control by each over its own affairs). The foregoing covenants exclude any matters that, individually or in the aggregate, could not reasonably be expected to have a change or effect that is material and adverse to the business, condition (financial or otherwise) or results of operations or prospects of such party and its subsidiaries taken as a whole (a "Material Adverse Effect").

Negative Covenants. CSW has agreed that, prior to the Effective Time, subject to certain exceptions and unless expressly contemplated by the Merger Agreement or otherwise consented to in writing by AEP, it will not do, and will not permit any of its subsidiaries to do, any of the following:

- except to the extent required by existing agreements and subject to certain other limited exceptions, (a) increase the compensation payable to or to become payable to any director or executive officer; (b) grant any severance or termination pay; (c) amend or otherwise modify the terms of any outstanding options, warrants or rights, the effect of which would be to make such terms more favorable to the holders thereof; (d) take any action to accelerate the vesting of any outstanding stock options; (e) amend or take any other actions to increase the amount or accelerate the payment or vesting of any benefit under any benefit plan; or (f) contribute, transfer or otherwise provide any cash, securities or other property to any grantee, trust, escrow or other arrangement that has the effect of providing assets for benefits payable pursuant to any termination or severance agreement;
- subject to certain limited exceptions, (a) enter into any employment or severance agreement with any director, officer or employee or (b) establish, adopt or enter into any new benefit plan;
- declare or pay any dividend on, or make any other distribution in respect of, outstanding shares of capital stock of CSW or certain of its subsidiaries, except for dividends declared and paid on the CSW Shares at approximately the same times and at a rate per share not to exceed the rate per share as declared and paid during the year ended December 31, 1997, intercompany dividends and distributions and dividends paid with respect to outstanding preferred stock of CSW subsidiaries;
- redeem, purchase or acquire, or offer to purchase or acquire, any outstanding equity securities of CSW or certain of its subsidiaries, except (a) as required by the terms of any outstanding equity securities, (b) in connection with the refunding or refinancing of preferred equity securities at a lower cost of funds, (c) in connection with open market purchases of CSW Shares to fund up to $10 million in any fiscal year of acquisitions not prohibited by the Merger Agreement, (d) as required to administer existing employee benefit, direct stock purchase and dividend reinvestment plans and (e) pursuant to certain other limited exceptions;
- split, combine or reclassify any of the CSW Shares or effect any recapitalization of CSW;
- offer, sell, issue or grant, or authorize the offering, sale, issuance or grant, of any Equity Securities, except issuances of CSW Shares issuable upon exercise of outstanding stock options and preferred stock of any CSW subsidiary to finance investments or capital contributions not prohibited by the Merger Agreement or to refinance existing preferred stock or indebtedness obligations of such subsidiary and subject to certain other limited exceptions;
- grant any lien with respect to any shares of capital stock of, or other equity interest in, any significant subsidiary of CSW owned by CSW or a subsidiary of CSW;
- acquire or agree to acquire any business or other entity, or otherwise acquire or agree to acquire any assets of any other person, except acquisitions of assets and businesses related to the core

domestic and U.K. regulated businesses in which CSW is currently engaged (the "Core Business") if the fair market value of the consideration paid therefor does not exceed 105% of the amount currently budgeted for such acquisitions and except for certain specified permitted transactions;

- except for certain specified permitted transactions and the disposition of assets other than generation assets and inventories in the ordinary course of business and certain legal requirements, sell or otherwise dispose of, or grant any lien with respect to, any of its material assets;
- adopt any amendments to its charter or bylaws that could reasonably be expected to have a Material Adverse Effect on the ability of CSW to perform its obligations under the Merger Agreement;
- change any of its significant accounting policies or take certain actions with respect to taxes;
- except in connection with certain specified permitted transactions or as required by law, incur any material obligation for borrowed money or purchase money indebtedness, other than drawings under existing or renewed credit lines, debt securities issued by subsidiaries to finance investments and capital expenditures permitted by the Merger Agreement and indebtedness incurred in the ordinary course of business;
- unless required by the terms thereof, release any third party from its obligations under any existing standstill provisions under a confidentiality or other agreement;
- except in connection with certain specified permitted transactions or as required by law, enter into any material contracts with any person (other than customers and vendors in the ordinary course of business) that provides for an exclusive arrangement or is substantially more restrictive or substantially less advantageous than existing material contracts of CSW;
- except in connection with certain specified permitted transactions or as required by law, make capital and non-fuel operational and maintenance expenditures relating to the Core Business in excess of 105% of the amount currently budgeted for such expenditures;
- except pursuant to existing legal obligations, make, or commit to make, any investments in, or loans or capital contributions to, or guarantee any obligations of, any joint venture in excess of 105% of the amount currently budgeted therefor by CSW; or
- agree in writing or otherwise to do any of the foregoing.

AEP has agreed that, prior to the Effective Time, subject to certain exceptions and unless expressly contemplated by the Merger Agreement or otherwise consented to in writing by CSW, it will not do, and will not permit any of its subsidiaries to do, any of the following:

- except to the extent required by existing agreements and subject to certain other limited exceptions, (a) increase the compensation payable to or to become payable to any director or executive officer; (b) grant any severance or termination pay; (c) amend or otherwise modify the terms of any outstanding options, warrants or rights, the effect of which would be to make such terms more favorable to the holders thereof; or (d) amend or take any other actions to increase the amount or accelerate the payment or vesting of any benefit under any benefit plan;
- subject to certain limited exceptions, (a) enter into any employment or severance agreement with any director, officer or employee or (b) establish, adopt or enter into any new benefit plan;
- declare or pay any dividend on, or make any other distribution in respect of, outstanding shares of capital stock of AEP or certain of its subsidiaries, except for dividends declared and paid on the AEP Shares at approximately the same times and at a rate per share not less than the rate per share as were declared and paid during the year ended December 31, 1997, intercompany dividends and distributions and dividends paid with respect to outstanding preferred stock of AEP subsidiaries;

- redeem, purchase or acquire, or offer to purchase or acquire, any outstanding equity securities of AEP or certain of its subsidiaries, except (a) as required by the terms of any outstanding equity securities, (b) in connection with the refunding or refinancing of preferred equity securities at a lower cost of funds, (c) in connection with open market purchases of AEP Shares to fund up to $10 million in any fiscal year of acquisitions not prohibited by the Merger Agreement, (d) as required to administer existing employee benefit, direct stock purchase and dividend reinvestment plans and (e) pursuant to certain other limited exceptions;
- split, combine or reclassify any of the AEP Shares or effect any recapitalization of AEP;
- offer, sell, issue or grant, or authorize the offering, sale, issuance or grant, of any equity securities, except issuances of AEP Shares not in excess of 10% of the amount currently outstanding, AEP Shares issuable upon exercise of outstanding stock options and preferred stock of any AEP subsidiary to finance investments or capital contributions not prohibited by the Merger Agreement or to refinance existing preferred stock or indebtedness obligations of such subsidiary and subject to certain other limited exceptions;
- grant any lien with respect to any shares of capital stock of, or other equity interest in, any significant subsidiary of AEP owned by AEP or a subsidiary of AEP;
- acquire or agree to acquire any business or other entity, or otherwise acquire or agree to acquire any assets of any other person, except acquisitions of assets and businesses related to the energy sector if the fair market value of the consideration paid therefor does not exceed $2.5 billion in the aggregate (reduced by the amount expended for capital expenditures (other than relating to the core domestic and U.K. regulated businesses in which AEP is currently engaged (the "AEP Core Business")) and with respect to certain joint ventures as permitted by the Merger Agreement);
- except for the disposition of assets other than generation assets and inventories in the ordinary course of business, divestitures of non-AEP Core Business and, except as required by law, sell or otherwise dispose of, or grant any lien with respect to, any of its material assets;
- adopt any amendments to its charter or bylaws that could reasonably be expected to have a Material Adverse Effect on the ability of AEP to perform its obligations under the Merger Agreement;
- change any of its significant accounting policies or take certain actions with respect to taxes;
- except as required by law, incur any material obligation for borrowed money or purchase money indebtedness, other than drawings under existing or renewed credit lines, debt securities issued by subsidiaries to finance investments and capital expenditures permitted by the Merger Agreement, indebtedness not in excess of $2.0 billion in the aggregate (in addition to the aggregate amount currently budgeted by AEP for indebtedness) and indebtedness incurred in the ordinary course of business;
- unless required by the terms thereof, release any third party from its obligations under any existing standstill provisions under a confidentiality or other agreement;
- except as required by law, enter into any material contracts with any person (other than customers and vendors in the ordinary course of business) that provides for an exclusive arrangement or is substantially more restrictive or substantially less advantageous than existing material contracts of AEP;
- except in connection with AEP Core Business or as required by law, make capital expenditures relating to the Core Business in excess of $2.5 billion less the amounts expended in connection with acquisitions and joint ventures as permitted by the Merger Agreement;
- except pursuant to existing legal obligations, make, or commit to make, any investments in, or loans or capital contributions to, or guarantee any obligations of, any joint venture in excess of $2.5 billion

(reduced by the amounts expended for capital expenditures (other than with respect to the AEP Core Business)) and acquisitions as permitted by the Merger Agreement; or

- agree in writing or otherwise to do any of the foregoing.

Access to Business of Other Party. During the pendency of the Merger Agreements, AEP and CSW each has agreed to afford, and to cause its subsidiaries to afford, to the other party and its representatives reasonable access at reasonable times to the officers, employees, agents, properties, offices and other facilities of such party and its subsidiaries and to such party's and such party's subsidiaries' books and records. Each of them also has agreed to furnish, and to cause its subsidiaries to furnish, to the other party and its representatives such information concerning the business, properties, contracts, records and personnel of such party and its subsidiaries as may be reasonably requested. If the Merger Agreement is terminated in accordance with its terms, a party that has received information pursuant to the Merger Agreement is obliged to return or destroy such information within ten days after a request therefor by the other party. All information furnished by either party pursuant to the Merger Agreement is subject to a confidentiality agreement executed and delivered by AEP and CSW prior to negotiation of the Merger Agreement.

Acquisition Proposals

In the Merger Agreement, AEP and CSW each have agreed that neither it nor any of its subsidiaries nor any of the officers and directors of it or its subsidiaries will, and have agreed to use its best efforts to cause its and its subsidiaries' employees, agents and representatives (including any investment banker, attorney or accountant retained by it or any of its subsidiaries) not to, directly or indirectly, initiate, solicit, encourage or otherwise facilitate (including by way of furnishing information) any inquiries or the making of any Acquisition Proposal (defined below), or to directly or indirectly have any discussion with or provide any confidential information or data to any person relating to an Acquisition Proposal, or engage in any negotiations concerning an Acquisition Proposal, or otherwise facilitate any effort or attempt to make or implement an Acquisition Proposal or accept an Acquisition Proposal. AEP and CSW have agreed in the Merger Agreement that nothing contained in the Merger Agreement will prevent either AEP or CSW or their respective Boards of Directors from (A) complying with Rule 14e-2(a) promulgated under the Securities Exchange Act of 1934 (the "Exchange Act"), with regard to an Acquisition Proposal; (B) in response to an unsolicited *bona fide* written Acquisition Proposal by any Person, recommending such an unsolicited bona fide written Acquisition Proposal to its stockholders, or withdrawing or modifying in any adverse manner its approval or recommendation of the Merger Agreement; or (C) engaging in any discussions or negotiations with, or providing any information to, any person in response to an unsolicited bona fide written Acquisition Proposal by any such person, if and only to the extent that, in any such case as is referred to in clause (B) or (C) of this sentence, (i) the AEP shareholders' approval of the Share Issuance and the Charter Amendment or the CSW stockholders' approval of the Merger, as the case may be, shall not have been obtained, (ii) the Board of Directors of AEP or CSW, as the case may be, concludes in good faith that such Acquisition Proposal (x) in the case of clause (B) of this sentence would, if consummated, constitute a Superior Proposal (defined below) or (y) in the case of clause (C) above could reasonably be expected to constitute a Superior Proposal, (iii) the Board of Directors of AEP or CSW, as the case may be, determines in good faith upon the basis of written advice of outside legal counsel that such action is necessary to act in a manner consistent with its fiduciary duties under applicable law, (iv) prior to providing any information or data to any person in connection with an Acquisition Proposal by any such person, such Board of Directors receives from such person an executed confidentiality agreement containing customary terms and provisions and (v) prior to providing any information or data to any person or entering into discussions or negotiations with any person, such Board of Directors notifies the other party immediately of such inquiries, proposals or offers received by, any such information requested from, or any such discussions or negotiations sought to be initiated or continued with, any of its representatives indicating, in connection with such notice, the name of such person and the material terms and conditions of any proposals or offers.

As used in this Joint Proxy Statement/Prospectus, the term "Acquisition Proposal" includes, with respect to AEP or CSW, the making of any proposal or offer with respect to a merger, reorganization, share exchange, consolidation, business combination, recapitalization, liquidation, dissolution or similar transaction involving, or any purchase or sale of all or any significant portion of the assets or 10% or more of the equity securities of, such party or any of its subsidiaries that, in any such case, could reasonably be expected to interfere with the completion of the Merger or the other transactions contemplated by the Merger Agreement. As used in this Joint Proxy Statement/Prospectus, the term "Superior Proposal" includes, with respect to AEP or CSW, a *bona fide* written Acquisition Proposal which the Board of Directors of AEP or the CSW, as the case may be, concludes in good faith (after consultation with its financial advisors and legal counsel), taking into account all legal, financial, regulatory and other aspects of the proposal and the person making the proposal, (i) would, if consummated, result in a transaction more favorable to the shareholders of AEP or CSW, as the case may be, from a strategic and financial point of view, than the transactions contemplated by the Merger Agreement and (ii) is reasonably capable of being completed (*provided* that for purposes of this definition, the reference to "10%" in the definition of "Acquisition Proposal" shall be deemed to be a reference to "50%" and "Acquisition Proposal" shall only be deemed to refer to a transaction involving AEP or CSW, as the case may be, or with respect to assets (including the shares of any subsidiary of AEP or CSW) of AEP or CSW, as the case may be, and its subsidiaries, taken as a whole, and not any of its subsidiaries alone).

Certain Post-Merger Matters

Once the Merger is consummated, Sub will cease to exist as a corporation, and CSW, as the Surviving Corporation, will succeed to all of the assets, rights and obligations of Sub.

Pursuant to the Merger Agreement, the charter and the bylaws of CSW, as in effect immediately prior to the Effective Time, will be the charter and bylaws of the Surviving Corporation until amended as provided therein and pursuant to the DGCL.

Board of Directors and Officers of Surviving Corporation

In the Merger Agreement, AEP and CSW have agreed that the Board of Directors of AEP following the Merger will consist of 15 members and will be reconstituted to include all then current board members of AEP, Mr. E.R. Brooks (the Chairman of CSW) and four additional outside directors of CSW to be nominated by AEP.

Stock Based Compensation and Employee Benefit Plans

Stock Options. The Merger Agreement provides that at the Effective Time, automatically and without any action on the part of the holder thereof, each CSW stock option will be assumed by AEP and will become an option to purchase AEP Shares. The number of shares of AEP Shares subject thereto will be obtained by multiplying the number of CSW Shares previously subject thereto (without regard to any vesting schedule) by the Exchange Ratio, and the exercise price per share of AEP Shares will be obtained by dividing the exercise price per share of CSW Shares stated therein by the Exchange Ratio. Otherwise, the terms and conditions of such CSW options will remain the same.

Based on the CSW stock options outstanding at the CSW Record Date and assuming none of such CSW stock options are exercised prior to the Effective Time, AEP will be required at the Effective Time to reserve an aggregate of 700,000 shares of AEP Shares for issuance upon exercise of CSW stock options assumed by AEP pursuant to the Merger.

The assumption by AEP of the CSW stock options pursuant to the Merger Agreement will not affect the vesting schedule of any such Shares. The CSW Incentive Plan provides that upon a Change of Control, as defined therein, including the closing of a Merger following which the stockholders of CSW own less than 75% of the surviving entity, outstanding stock options will be fully exercisable as of the date of the Change of Control. For information as to the holdings of CSW stock options by directors and executive officers of CSW, see "THE MERGER—Interests of Certain Persons in the Merger—Ownership of CSW Shares; Stock Options." In addition, the Change in Control Agreements also provide for the acceleration of CSW Shares granted to parties to such Change in Control Agreements. For information regarding the effect of the Change in Control Agreements on options held by those executive officers of CSW who are parties to the Change in Control Agreements, see "THE MERGER—Interests of Certain Persons in the Merger—CSW Long-Term Incentive Plan and Change in Control Agreements."

Other Stock-Based Compensation. Certain types of stock-based compensation other than stock options are outstanding under the CSW Incentive Plan, LTIP and the CSW Director's Plan. AEP has agreed to assume the LTIP and the CSW Director's Plan with respect to any stock-based compensation payable in the form of CSW Shares as a result of the Merger ("Other Compensation") and to substitute AEP Shares under such assumed Other Compensation (the "Assumed Other Compensation"). The number of shares of AEP Shares issuable with respect to assumed Other Compensation will be the number of whole AEP Shares which the holder of the Other Compensation would have received upon consummation of the Merger if the Other Compensation had been paid in full immediately prior to the Merger.

Separate Company Plans. AEP will continue the CSW employee benefit plans from the Effective Time through July 1, 2002, without adverse change except that (a) any CSW Share investment fund maintained under any plan will be replaced by an AEP Share investment fund or traditional investment fund as determined by AEP, (b) premiums under the CSW medical, dental, life, accidental death and dismemberment and disability insurance plans may be increased (other than with respect to participants who had retired from CSW or its subsidiaries prior to 1993 or their survivors), and (c) changes required by law may be made. AEP has agreed that after July 1, 2002, it will provide employees of CSW and its subsidiaries with employee benefits that are in the aggregate as least as favorable as the employee benefits provided to similarly situated employees of AEP and its subsidiaries and, if any AEP employee benefit plan is provided to employees of CSW and its subsidiaries, the AEP employee benefit plan will recognize such employees' service with CSW and its subsidiaries for all purposes, including the accrual of benefits and the eligibility to receive benefits. AEP has also agreed that no earlier than July 1, 2002, AEP will merge the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Cash Balance Plan") with a defined benefit pension plan of AEP or its subsidiaries, and that the retirement benefit for employees of CSW and its subsidiaries who become participants in the merged plan will be determined under the AEP pension plan formula for all years of service, but such benefit will not be less than such employees' benefit accrued under the CSW Cash Balance Plan immediately prior to the plan Merger, plus the benefit determined under the AEP pension plan formula for years of service beginning after the plan Merger. AEP has agreed that if the employees of CSW and its subsidiaries become participants in a health plan of AEP or its subsidiaries, AEP will waive all pre-existing condition limitations with respect to such employees and, if such participation is effective other than on the first day of a calendar year, such employees will receive credit for any co-payments and deductibles incurred by such employees in the same calendar year under the CSW medical plan.

Retiree and Disability Benefits. From and after July 1, 2002, AEP will provide access to retiree medical and life insurance coverage to any employee or director of CSW and its subsidiaries who retires or becomes disabled prior to July 1, 2002, and who was eligible for retiree medical and life insurance coverage under the CSW plans in effect on the date of such employee or director's retirement or termination. AEP will also continue the retiree medical and life insurance coverage for employees or directors who retired or became disabled prior to 1993 without adverse change to such employees or directors. Further, AEP will provide medical coverage without adverse change to employees who become disabled before July 1, 2002, as long as such employees satisfy the requirements of the Central and South West Corporation System Employees' Disability Income Plan on the date of such employees' retirement or termination.

Certain Nonqualified Arrangements. AEP will maintain the Central and South West System Special Executive Retirement Plan (the "SERP") and the Central and South West Corporation Executive Deferred Compensation Plan (the "DCP") from and after the Effective Time until July 1, 2002, without adverse change to any employee until all benefits are paid out in accordance with the plans, but no deferrals will be permitted under the DCP after the Effective Time. If the SERP or the Central and South West Corporation Executive Deferred Savings Plan (the "DSP") is terminated or otherwise discontinued after July 1, 2002, AEP will make available to the class of employees of CSW and its subsidiaries that was eligible to participate in the SERP and the DSP any nonqualified deferred compensation plans that AEP maintains to supplement the AEP qualified employee benefit plans and the employees' service with CSW and its subsidiaries will be recognized for all purposes under such plans. Further, AEP's supplemental plans will assume the obligation of the SERP or DSP to pay the accrued benefits thereunder at the time of any termination or discontinuance of the SERP or DSP.

Conditions to the Consummation of the Merger

The respective obligations of AEP and CSW to consummate the Merger are subject to the satisfaction of the following conditions, any or all of which may be waived in writing by CSW and AEP, in whole or in part, to the extent permitted by applicable law; (i) the Registration Statement shall have been declared effective by the SEC under the Securities Act, no stop order suspending the effectiveness of the Registration Statement shall have been issued by the SEC and no proceedings for that purpose shall have been initiated by the SEC; (ii) the Merger Agreement shall have been approved and adopted by the requisite vote of the shareholders of CSW and the Share Issuance and the Charter Amendment shall have been approved and adopted by the stockholders of AEP; (iii) no court or governmental authority shall have enacted, issued, promulgated, enforced or entered any law, regulation or order (whether temporary, preliminary or permanent) that is in effect and that has the effect of making the Merger illegal or otherwise prohibiting consummation of the Merger; (iv) all judgments, orders or decrees of any court or governmental authority ("Orders") necessary for the consummation of the Merger shall have been obtained and shall have become Final Orders (as defined below) and no Final Orders shall impose terms or conditions or qualifications that, individually or in the aggregate, could reasonably be expected to have a Material Adverse Effect on the combined companies; (v) AEP and CSW shall each have been advised in writing on the closing date by its independent public accountants that the Merger will qualify as a pooling of interests transaction in accordance with generally accepted accounting principles and the applicable SEC regulations; (vi) the AEP Shares to be issued pursuant to the Merger shall have been listed, subject to official notice of issuance, on the NYSE; and (vii) there shall not have occurred and remain in effect a Divestiture Event (as defined below) with respect to AEP or CSW. For the purposes of this Joint Proxy Statement/Prospectus, a "Final Order" is defined as an Order that has not been reversed, stayed, enjoined, set aside, annulled or suspended, with respect to which any waiting period prescribed by law before the Merger may be consummated has expired (but without the requirement for expiration of any applicable rehearing or appeal period) and as to which all conditions to the consummation of the Merger prescribed by law, regulation or order have been satisfied, and "Divestiture Event" is defined as the adoption of a law or the issuance by a governmental authority of any regulation or order that requires the divestiture of a substantial portion of the generating assets of CSW or AEP.

The obligation of AEP to effect the Merger is also subject to the satisfaction at or prior to the Effective Time of the following conditions, any or all of which may be waived in writing by AEP, in whole or in part, to the extent permitted by applicable law; (i) each of the representations and warranties of CSW contained in the Merger Agreement shall be true and correct in all material respects as of the date of the Merger Agreement and as of the closing as though made again as of the closing (except for representations and warranties that expressly speak only as of a specific date or time other than the date of the Merger

Agreement or the closing date which need only be true and correct as of such date); and (ii) CSW shall have performed or complied in all material respects with all agreements and covenants required by the Merger Agreement to be performed or complied with by it on or prior to the closing date. For purposes of clause (i), no representation or warranty of CSW shall be deemed to be untrue as a result of the occurrence of a Divestiture Event or any change or effect arising out of any foreign, federal or state legislative or regulatory action with respect to (a) the regulation or deregulation of the electric utility industry or (b) health or environment, including the conservation or protection of the environment.

The obligation of CSW to effect the Merger is also subject to the satisfaction at or prior to the Effective Time of the following conditions, any or all of which may be waived in writing by CSW, in whole or in part, to the extent permitted by applicable law: (i) each of the representations and warranties of AEP and Sub contained in the Merger Agreement shall be true and correct in all material respects as of the date of the Merger Agreement and as of the closing as though made again as of the closing (except for representations and warranties that expressly speak only as of a specific date or time other than the date of the Merger Agreement or the closing date which need only be true and correct as of such date); and (ii) AEP and Sub shall have performed or complied in all material respects with all agreements and covenants required by the Merger Agreement to be performed or complied with by them on or prior to the closing date. For purposes of clause (i), no representation or warranty of AEP shall be deemed to be untrue as a result of the occurrence of a Divestiture Event or any change or effect arising out of any foreign, federal or state legislative or regulatory action with respect to (a) the regulation or deregulation of the electric utility industry or (b) health or environment, including the conversation or protection of the environment.

There can be no assurance that all of the conditions to the Merger will be satisfied.

Termination

The Merger Agreement may be terminated at any time prior to the Effective Time, whether before or after the required vote of the shareholders of AEP or CSW: (a) by mutual written consent of AEP and CSW; (b) by AEP or CSW (such party, the "Terminating Party"), upon two business days' prior written notice to the other (the "Breaching Party"), upon a breach of any representation, warranty, covenant or agreement on the part of the Breaching Party made in the Merger Agreement or if any representation or warranty of the Breaching Party shall have become untrue, in either case such that the Terminating Party's conditions to effecting the Merger would not be satisfied, subject to a cure period under certain circumstances; (c) by either CSW or AEP, upon two business days' prior written notice to the other, if there shall occur any Divestiture Event except that no such termination shall be permitted so long as the Divestiture Event is capable of being vacated, lifted or reversed prior to the Termination Date (as defined below) through the exercise of commercially reasonable efforts; (d) by either AEP or CSW, upon two business days' prior written notice to the other, if there shall be any law or regulation issued or adopted or any order which is final and non-appealable preventing the consummation of the Merger, subject to a limited exception; (e) by either AEP or CSW, by written notice to the other, if the Merger shall not have been consummated before December 31, 1999 (the "Termination Date"); *provided, however,* that the Merger Agreement may be extended by written notice to a date not later than June 30, 2000 if the Merger shall not have been consummated as a result of CSW, AEP or Sub's having failed by December 31, 1999 to satisfy the condition of obtaining the required regulatory approvals or the condition requiring the absence of a Divestiture Event described above in clauses (iii) and (iv), respectively, under "Conditions to the Consummation of the Merger" and provided that the right to terminate the Merger Agreement under the provision described in this clause (e) will not be available to any party whose failure to fulfill any obligation under the Merger Agreement has been the cause of, or resulted in, the failure of the Effective Time to occur on or before such date; (f) by either AEP or CSW, upon two business days' prior written notice, if the Merger Agreement shall fail to receive the requisite vote for approval and adoption by the stockholders of CSW or the Share Issuance and Charter Amendment shall fail to receive the requisite vote for approval and adoption by the stockholders of AEP; (g) by AEP or CSW, at any time prior to, in the case of AEP receipt of shareholders' approval of the Share Issuance and the Charter Amendment, and in the case of CSW, receipt of CSW stockholders' approval of the Merger Agreement, upon two business days' prior written notice to the other, if the Board of Directors of AEP or CSW, as the case may be, shall approve a Superior Proposal; provided, however, that (1) such party shall have complied with the covenant regarding Acquisition Proposals described above under "The Merger Agreement—Acquisition Proposals", (2) the Board of Directors of AEP or CSW, as the case may be, shall have concluded in good faith, after giving effect to all concessions which may be offered in negotiations entered into pursuant to clause (4) below, on the basis of the advice of its financial advisors and outside counsel, that such proposal is a Superior Proposal, (3) the Board of Directors of AEP or CSW, as the case may be, shall have concluded in good faith, after receipt of written advice of outside counsel, that notwithstanding all concessions which may be offered by the other party in negotiations entered into pursuant to clause (4) below, such action is necessary for the Board of Directors to act consistent with its fiduciary duties; and (4) prior to any such termination, AEP or CSW, as the case may be, will, and will cause its respective financial and legal advisors to, negotiate with the other to make such adjustments in the terms and conditions of the Merger Agreement as would enable AEP or CSW, as the case may be, to proceed with the transactions contemplated therein on such adjusted terms; (h) by AEP or CSW, upon two business days' prior written notice to the other, if the Board of Directors of the other party or any committee thereof (1) shall withdraw or modify in any manner adverse to the Terminating Party its approval or recommendation of, in the case of the Board of Directors of CSW, the Merger Agreement and in the case of the Board of Directors of AEP, the Charter Amendment and the Share Issuance, (2) shall fail to reaffirm such approval or recommendation upon the Terminating Party's request, (3) shall approve or recommend any Superior Proposal or (4) shall resolve to take any of the actions specified in clause (1), (2) or (3); and (i) by either AEP or CSW, by written notice to the other, if (1) a third party acquires securities representing greater than 50% of the voting power of the outstanding voting securities of the other party or (2) individuals who as of the date hereof constitute the board of directors of such other party (together with any new directors whose election by such board of directors or whose nomination for election by the stockholders of such party was approved by a vote of a majority of the directors of such party then still in office who were either directors as of the date of the Merger Agreement or whose election or nomination for election was approved prior to the Merger Agreement) cease for any reason to constitute a majority of the Board of Directors of such other party then in office.

Subject to limited exceptions, including the survival of the parties' agreements to pay certain fees and reimburse expenses to the other under certain circumstances, as discussed below, in the event of the termination of the Merger Agreement, the Merger Agreement shall become void, there shall be no liability on the part of AEP, Sub or CSW (or any of their respective officers and directors) to the other, and all rights and obligations of the parties thereto shall cease, except that no party will be relieved from its obligations with respect to any breach of the Merger Agreement.

Expenses and Fees

All expenses incurred by AEP, Sub and CSW will be borne by the party incurring such expenses; *provided, however,* that the allocable share of AEP and Sub, as a group, and CSW for all expenses related to printing, mailing and filing this Joint Proxy Statement/Prospectus and all SEC and other regulatory filing fees incurred in connection with the Registration Statement or this Joint Proxy Statement/Prospectus shall be borne one-half each; and *provided, further,* that AEP may, at its option, pay any expenses of CSW that are solely and directly related to the Merger.

If the Merger Agreement is terminated pursuant to the provision described above in clause (g) under "Termination" ("Clause (g)"), pursuant to the provision described above in clause (b) under "Termination" ("Clause (b)"), pursuant to the provision described above in clause (h) under "Termination" ("Clause (h)") or pursuant to the provision described above in clause (i) under "Termination" ("Clause (i)"), then the breaching party or party whose Board of Directors has exercised its fiduciary out as described under Clause (g) or changed its recommendation or the party whose stock has been acquired or whose Board of Directors has changed, as the case may be, shall promptly (but not later than five business days after notice of the amount due is received) pay to the other party, as liquidated damages and expense reimbursement, an amount equal to $20 million (the "Termination Fee").

If (i) the Merger Agreement is terminated pursuant to (A) the provision described above in clause (e) under "Termination", (B) Clause (g), (C) the provision described above in clause (f) under "Termination", (D) Clause (h) or (E) Clause (b); and (ii) at the time of such termination (or in the case of clause (i)(C) of this sentence, prior to the meeting of such party's shareholders) there shall have been an Acquisition Proposal involving CSW or AEP (as the case may be, the "Target Party") or any of its affiliates which, at the time of such termination (or such meeting, as the case may be), shall not have been (x) rejected by the Target Party and its Board of Directors and (y) withdrawn by the third party; and (iii) within eighteen months of any such termination described in clause (i) above, the Target Party or any of its affiliates becomes a subsidiary of such offeror or a subsidiary of an affiliate of such offeror or accepts a written offer or enters into a written agreement to consummate or consummates an Acquisition Proposal with such offeror or an affiliate thereof, then such Target Party (jointly and severally with its affiliates), upon the signing of a definitive agreement relating to such Acquisition Proposal, or, if no such agreement is signed, then at the closing (and as a condition to the closing) of such Target Party's becoming such a subsidiary or of such Acquisition Proposal, shall pay CSW or AEP, as the case may be, a termination fee equal to $225 million (the "Topping Fee") plus Expenses (as defined below) of such party not in excess of $20 million ("Out-of-Pocket Expenses"). If the Merger Agreement is terminated by CSW or AEP pursuant to Clause (i), then CSW or AEP, as the case may be, shall pay immediately the terminating party the Topping Fee plus Out-of-Pocket Expenses.

As used in this Joint Proxy Statement/Prospectus, the term "Expenses" includes all reasonable out-of-pocket expenses (including all fees and expenses of counsel, accountants, investment bankers, experts and consultants to a party hereto and its affiliates) incurred by a party or on its behalf in connection with or related to the authorization, preparation, negotiation, execution and performance of the Merger Agreement, the preparation, printing, filing and mailing of the Registration Statement, this Joint Proxy Statement/Prospectus, the solicitation of stockholder approvals and all other matters related to the consummation of the transactions contemplated by the Merger Agreement.

If termination fees are payable pursuant to the termination provisions contained in the Merger Agreement, the aggregate amount payable to either AEP or CSW and each of their respective affiliates will not exceed $245 million (including Expenses).

Amendment and Waiver

The Merger Agreement may be amended by the parties thereto by action taken by or on behalf of their respective Boards of Directors at any time prior to the Effective Time, *provided, however,* that after approval of the Merger by the stockholders of CSW, no amendment may be made that would alter or change the type of consideration into which each share of CSW Shares will be converted pursuant to the Merger Agreement upon consummation of the Merger, alter or change any term of the certificate of incorporation of CSW to be affected by the Merger or alter or change any of the terms and conditions that would adversely affect the holders of any class or series of CSW securities. Any such amendment to the Merger Agreement must be set forth in a writing signed by AEP, Sub, and CSW. At any time prior to the Effective Time, any party to the Merger Agreement may (i) extend the time for the performance of any of the obligations or other acts of the other party thereto, (ii) waive any inaccuracies in the representations and warranties of the other party contained therein or in any document delivered pursuant thereto and (iii), to the extent permitted by law, waive compliance by the other party with any of the agreements or conditions contained therein. Any such extension or waiver shall be valid only if set forth in a writing signed by the party or parties to be bound by such extension or waiver.

Indemnification

The Merger Agreement provides that, for a period of six years after the Effective Time, (i) the certificate of incorporation and bylaws of the Surviving Corporation (which will contain indemnification provisions substantially equivalent to the current provisions in the CSW Charter and Bylaws) as in effect immediately following the Effective Time shall not be amended to reduce or limit the rights of indemnity afforded to the present and former directors and officers of CSW thereunder or as to the ability of the Surviving Corporation to indemnify such persons or to hinder, delay or make more difficult the exercise of such rights of indemnity or the ability to indemnify with respect to any claims made against such persons arising from their service in such capacities; and (ii) AEP shall cause to be maintained in effect the current policies of directors' and officers' liability insurance maintained by CSW (or substitute policies under certain circumstances) with respect to claims arising from facts or events that occurred before the Effective Time; *provided, however,* that in no event shall AEP or the Surviving Corporation be required to expend more than 200% of the current annual premiums paid by CSW for such insurance.

REGULATORY APPROVALS

Set forth below is a summary of the material regulatory requirements affecting the Merger. Additional consents from or notifications to governmental agencies may be necessary or appropriate in connection with the Merger.

Under the Merger Agreement, AEP and CSW have agreed to use all commercially reasonable efforts to obtain any permits, orders and other governmental authorizations necessary, proper or advisable to consummate and make effective the transactions contemplated by the Merger Agreement. While AEP, CSW and their subsidiaries believe that they will receive the requisite regulatory approvals of the Merger, including favorable ratemaking treatment, there can be no assurance as to the timing of such approvals, the ability to obtain such approvals or that such approvals will contain satisfactory terms and conditions. It is a condition to the consummation of the Merger that final orders from the various federal and state commissions described above necessary for the consummation of the Merger and other transactions contemplated by the Merger Agreement have been obtained and do not impose terms, conditions or qualifications that, individually or in the aggregate, could reasonably be expected to have a material adverse effect on the combined company. There can be no assurance that any such approvals will be obtained or, if obtained, will not contain terms, conditions or qualifications that cause such approvals to fail to satisfy such condition to the consummation of the Merger or that such orders will not be appealed by intervenors to the appropriate courts.

Antitrust Considerations

The HSR Act and the rules and regulations thereunder provide that certain transactions (including the Merger) may not be consummated until certain information has been submitted to the Antitrust Division of the Department of Justice ("Antitrust Division") and the Federal Trade Commission (the "FTC") and the specified HSR Act waiting period requirements have been satisfied. AEP and CSW will provide their respective premerger notifications pursuant to the HSR Act. The expiration or earlier termination of the HSR Act waiting period would not preclude the Antitrust Division or the FTC from challenging the Merger on antitrust grounds. Neither AEP nor CSW believes that the Merger will violate federal antitrust laws. If the Merger is not consummated within 12 months after the expiration or earlier termination of the initial HSR Act waiting period, AEP and CSW must submit new information to the Antitrust Division and the FTC, and a new HSR Act waiting period must expire or be earlier terminated before the Merger may be consummated.

1935 Act

In connection with the Merger, AEP and CSW are required to obtain SEC approval under various sections of the 1935 Act (including Sections 6(a) and 9(a), which govern certain issuances of securities and certain acquisitions of securities, utility assets or an interest in any other business by any company in a registered holding company system). AEP and CSW will file a joint application to the SEC seeking the necessary approvals under the 1935 Act.

Under the standards applicable to transactions subject to approval pursuant to Section 9(a) of the 1935 Act, the SEC is directed to approve the Merger unless it finds that (i) the Merger would tend towards detrimental interlocking relations or a detrimental concentration of control, (ii) the consideration to be paid in connection with the Merger is not reasonable, (iii) the Merger would unduly complicate the capital structure of the applicant's holding company system or would be detrimental to the proper functioning of the applicant's holding company system, or (iv) the Merger would violate applicable state law. To approve the proposed Merger, the SEC also must find that the Merger would tend towards the development of an integrated public utility system and would otherwise conform to the 1935 Act's integration and corporate simplification standards.

Atomic Energy Act

CSW, through its wholly-owned subsidiary CPL, owns a 25.2% interest in the South Texas Project, a two-unit nuclear electric generating station. The South Texas Project is operated by the STP Nuclear Operating Company ("STP Operating"), a Texas non-profit corporation, which is jointly-owned by CPL and the other owners of the South Texas Project. CPL holds NRC licenses with respect to its ownership interests in the South Texas Project and STP Operating. Section 184 of the Atomic Energy Act provides that no license may be transferred, assigned or in any manner disposed of, directly or indirectly, through transfer of control of any license to any person, unless the NRC finds that the transfer is in accordance with the provisions of the Atomic Energy Act and gives its consent in writing. CPL will seek approval from the NRC for transfer of control of its NRC licenses as a result of the merger of its parent, CSW, with a subsidiary of AEP. After the Merger, CPL, as an operating utility subsidiary of AEP, will continue to own the identical pre-Merger interests in the South Texas Project and STP Operating.

Federal Power Act

Section 203 of the Federal Power Act provides that no public utility may sell or otherwise dispose of its jurisdictional facilities, directly or indirectly merge or consolidate its facilities with those of any other person, or acquire any security of any other public utility, without first having obtained authorization from the FERC. AEP and CSW will file a joint application with the FERC seeking approval of the Merger. Under Section 203 of the Federal Power Act, the FERC will approve a merger if it finds the merger to be "consistent with the public interest."

Under the FERC's 1996 Utility Merger Policy Statement, if one or more state commissions with regulatory jurisdiction over a Merger applicant's retail rates lacks the authority to approve a merger, and raises concerns at the FERC regarding the effect of the proposed merger on state regulation, the FERC may hold a hearing to address the issue. AEP has advised that it does not believe that formal approval of the Merger is required by the state commissions with jurisdiction over its utility subsidiaries, i.e., the Indiana, Kentucky, Ohio, Michigan, Tennessee, Virginia and West Virginia commissions.

Communications Act

CSW, itself or through one or more subsidiaries, holds various radio licenses subject to the jurisdiction of the FCC under Title III of the Communications Act. Under Section 310 of the Communications Act, no station license may be assigned or transferred, directly or indirectly, except upon application to and approval by the FCC. AEP and CSW intend to file applications with the FCC seeking approval for the transfer of control of these licenses as a result of the Merger.

Arkansas Commission

CSW's wholly-owned subsidiary, SWEPCO, is subject to the jurisdiction of the Arkansas Commission. Pursuant to Section 23-3-306(b) of the Arkansas Statutes, Arkansas Commission approval is required before any person may merge with or otherwise acquire control of a domestic public utility. AEP, CSW and SWEPCO will seek Arkansas Commission approval of the Merger.

The Arkansas Commission must approve a merger application unless it finds that one or more of five adverse circumstances would result from the transaction. The circumstances include an adverse effect on the public utility's existing obligations or the quality of service, a reduction in competition for the provision of utility services within the state, and an adverse effect on the financial condition of the public utility.

Louisiana Commission

CSW's wholly-owned subsidiary, SWEPCO, is subject to the jurisdiction of the Louisiana Commission. Pursuant to Louisiana Statutes Section 45:1164, the Louisiana Commission is granted general supervisory authority over public utilities operating in the state and, under this authority, the Louisiana Commission has held that its approval or non-opposition is required prior to the sale, lease, merger, consolidation, stock transfer, or any other change of control or ownership of a public utility subject to its jurisdiction. AEP, CSW and SWEPCO will seek Louisiana Commission approval of, or non-opposition to, the Merger.

·The Louisiana Commission reviews merger applications pursuant to an 18 factor test that generally relates to the impact of the transaction on competition, the financial condition of the utility, quality of service, public health and safety, employment, and other similar "public interest" matters.

Oklahoma Commission

CSW's wholly-owned subsidiary, PSO, is subject to the jurisdiction of the Okalahoma Commission. The Oklahoma statutes concerning mergers and acquisitions of public utilities are substantially identical to the sections of the Arkansas Statutes discussed above. Thus, Oklahoma Commission approval is required before any person may merge with or otherwise acquire control of an Oklahoma public utility; and the Oklahoma Commission is required to approve such merger or acquisition of control unless it finds that the transaction will result in one or more of a list of adverse circumstances, which are substantially identical to the adverse circumstances listed above with respect to Arkansas. AEP, CSW and PSO will seek the approval of the Oklahoma Commission consistent with these requirements.

Texas Commission

Three of CSW's wholly-owned subsidiaries, CPL, SWEPCO and WTU, are subject to the jurisdiction of the Texas Commission. Pursuant to Section 14.101 of the Texas Utilities Code, each transaction involving the sale of at least 50 percent of the stock of a public utility must be reported to the Texas Commission within a reasonable time. AEP, CSW, CPL, SWEPCO and WTU will report the Merger to the Texas Commission for its review.

In reviewing a transaction involving the sale of at least 50 percent of the stock of a Texas utility, the Texas Commission is required to determine whether the action is consistent with the public interest, taking into consideration factors such as the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, transferred, or consolidated, and whether the transaction will adversely affect the health or safety of customers or employees, result in the transfer of jobs of Texas citizens to workers domiciled outside of Texas, or result in the decline of service. If the Texas Commission determines that a transaction is not in the public interest, it may take the effect of the transaction into consideration in ratemaking proceedings and disallow the effect of such transaction if such transaction will unreasonably affect rates or service.

Affiliate Contracts

In connection with the Merger, AEP, CSW and their subsidiaries will need to enter into or amend agreements related to the provision by affiliates of the combined companies of various services, including management, supervisory, construction, engineering, accounting, legal, financial or similar services. The approval or non-opposition of certain state regulatory commissions and the SEC is required with respect to the creation or amendment of certain inter-affiliate agreements. AEP, CSW and their subsidiaries will file such agreements with the appropriate state regulatory commissions and the SEC.

Other Regulatory Matters

CSW and its subsidiaries have obtained from various regulatory authorities certain franchises, permits and licenses which may need to be renewed, replaced or transferred as a result of the Merger, and approvals, consents or notifications may be required in connection with such renewals, replacements or transfers.

AEP's operating utility companies are subject to the jurisdiction of utility regulatory commissions in the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. On January 16, 1998, the Public Utilities Commission of Ohio opened a docket regarding the Merger and the Kentucky Public Service Commission (the "Kentucky Commission"), by letter, requested that AEP file an application for the Kentucky Commission's approval of the Merger. On March 13, 1998, after having received a response from AEP, the Executive Director of the Kentucky Commission sent a letter to AEP indicating, based on its analysis of the information provided to date, that the Merger would require prior Kentucky Commission approval, but stating that if AEP is aware of any controlling case law to the contrary, the issue would be revisited. AEP believes that the approval of the utility regulatory commissions in these states is not required to consummate the Merger.

Regulatory commissions of states where AEP's and CSW's utility subsidiaries operate may intervene in the federal regulatory proceedings. In addition, such regulatory commissions regulate the rates charged to utility customers within their jurisdictions. In approving rates, each state may take into account savings resulting from, and other effects of, the Merger.

CERTAIN LITIGATION

Two lawsuits have been filed in Delaware state court seeking to enjoin the Merger. CSW and each of its directors have been named as defendants in both cases. The first suit, *Robert Lewis v. William R. Howell, et al.*, alleges that the CSW Rights Plan, approved by the CSW Board on September 27, 1997 and which became effective on December 19, 1997, constitutes a "poison pill" precluding acquisition offers and resulting in a heightened fiduciary duty on the part of the CSW Board to pursue an auction-type sale process to obtain the best value for CSW stockholders. The second suit, *Robert Lewis and Max Grill v. Glen Biggs, et al.*, alleges that the Merger is unfair to CSW stockholders in that it does not recognize the underlying intrinsic value of CSW's assets and its future profitability. This second suit also seeks an auction-type sale process. CSW believes that both suits are without merit and intends to defend them vigorously.

THE AEP MEETING—ADDITIONAL MATTERS

Election of Directors

Eleven directors are to be elected at the AEP Meeting to hold office until the next annual meeting and until their successors have been elected. The By-Laws of AEP provide that the number of directors of AEP shall be such number, not less than 9 nor more than 17, as shall be determined from time to time by resolution of AEP's Board of Directors.

On December 17, 1997, AEP's Board of Directors adopted a resolution increasing the number of directors constituting the entire Board from 12 to 13, and elected Dr. Kathryn D. Sullivan to fill the vacancy thus created. In addition, on January 28, 1998, AEP's Board of Directors adopted a resolution reducing the number of directors from 13 to 11, effective on the date of the AEP Meeting. Messrs. DeMaria and Maloney, each currently a director, will be retiring from the Board and not standing for reelection.

The 11 nominees named on pages 105-107 were selected by AEP's Board of Directors on the recommendation of the Committee on Directors of the Board. The proxies named on the proxy card or their substitutes will vote for the Board's nominees, unless instructed otherwise. Shareholders may withhold authority to vote for any or all of such nominees on the proxy card. Except for Dr. Sullivan, who is standing for election for the first time, all of the Board's nominees were elected by the shareholders at the 1997 annual meeting. It is not expected that any of the nominees will be unable to stand for election or be unable to serve if elected. In the event that a vacancy in the slate of nominees should occur before the meeting, the proxies may be voted for another person nominated by AEP's Board of Directors or the number of directors may be reduced accordingly.

The following brief biographies of the nominees include their principal occupations, ages on the date of this Joint Proxy Statement/Prospectus, accounts of their business experience and the names of certain companies of which they are directors. Data with respect to the number of AEP Shares and stock-based units beneficially owned by each of them appears on page 117.

Attachment 1
Page 111 of 215
KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 4

Nominees For Director

John P. DesBarres

Investor/Consultant,
Rancho Palos Verdes, California

Age 58

Director since April 1997

Received an associate degree in electrical engineering from Worcester Junior College in 1960 and completed the Harvard Business School Program for Management Development in 1975 and the Massachusetts Institute of Technology Sloan School Senior Executive Program in 1984. Joined Sun Company (petroleum and natural gas) in 1963, holding various positions until 1979, when he was elected president of Sun Pipe Line Company (1979-1988) (crude oil products). Chairman, president and chief executive officer of Sante Fe Pacific Pipelines, Inc. (1988-1991) (petroleum products pipeline). President and chief executive officer (1991-1995) and chairman (1992-1995) of Transco Energy Company (natural gas). A director of Texas Eastern Products Pipeline Company, which is the general partner of TEPPCO Partners, L.P.

E. Linn Draper, Jr.

Chairman, President and Chief Executive Officer of AEP and AEP Service Corporation; Chairman and Chief Executive Officer of all other major Company subsidiaries

Age 56

Director since 1992

Received his B.A. and B.S. (chemical engineering) degrees from Rice University in 1964 and 1965, respectively, and Ph.D. (nuclear engineering) in 1970 from Cornell University. Joined Gulf States Utilities Company, an unaffiliated electric utility, in 1979. Chairman of the board, president and chief executive officer of Gulf States (1987-1992). Elected president of AEP and president and chief operating officer of AEP Service Corporation in March 1992 and chairman of the board and chief executive officer of AEP and all of its major subsidiaries in April 1993. A director of BCP Management, Inc., which is the general partner of Borden Chemicals and Plastics L.P., and CellNet Data Systems, Inc.

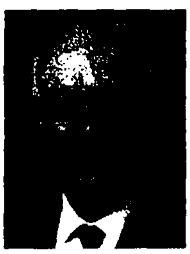
Robert M. Duncan

Director and Trustee,
Columbus, Ohio

Age 70

Director since 1985

Received his B.S. and J.D. from The Ohio State University in 1948 and 1952, respectively. After two years in the private practice of law, held a series of governmental legal positions culminating in service as a judge for the U.S. District Court for the Southern District of Ohio, a position held from 1974 to 1985. Private practice of law (1985-1991). Vice president and general counsel, The Ohio State University (1992-1994). A trustee of Nationwide Investing Foundation, Nationwide Investing Foundation II, Nationwide Separate Account Trust and Financial Horizons Investment Trust.



Robert W. Fri

Director, National
Museum of Natural History
(Smithsonian Institution),
Washington, D.C.

Age 62

Director since 1995

Holds a B.A. from Rice University and an M.B.A. from Harvard Business School. Associated with McKinsey & Company, Inc., management consulting firm, from 1963 to 1971 and again from 1973 to 1975, being elected a principal in the firm in 1968. From 1971 to 1973, served as first Deputy Administrator of the Environmental Protection Agency, becoming Acting Administrator in 1973. Was first Deputy and then Acting Administrator of the Energy Research and Development Administration from 1975 to 1977. From 1978 to 1986 was President of Energy Transition Corporation. President and director of Resources for the Future (non-profit research organization) from 1986 to 1995 and became senior fellow emeritus in 1996. Assumed his present position with the National Museum of Natural History in 1996. A director of Hagler Bailly, Inc.

Lester A. Hudson, Jr.

Chairman, H&E Associates, Greenville, South Carolina

Age 58

Director since 1987

Received a B.A. from Furman University in 1961, an M.B.A. from the University of South Carolina in 1965 and Ph.D. (industrial management) from Clemson University in 1997. Joined Dan River Inc. (textile fabric manufacturer) in 1970 and was elected president and chief operating officer in 1981 and chief executive officer in 1987. Resigned from Dan River in 1990. Joined WundaWeve Carpets, Inc. (carpet manufacturer) as chairman, president and chief executive officer in 1990. Chairman of WundaWeve in 1991. Vice chairman of WundaWeve (1993-1995). Chairman, H&E Associates (investment firm) in 1995. A director of American National Bankshares Inc. and Greenville Hospital System Foundation. Business Strategy Instructor, Clemson University.

Leonard J. Kujawa

International Energy Consultant, Atlanta, Georgia

Age 65

Director since February 1997

Received his B.B.A. in 1954 and M.B.A. in 1955 from the University of Michigan. Joined Arthur Andersen LLP (accounting and consulting firm) in 1957 and became a partner in 1968, specializing in the electric and telecommunications industries. Worldwide Director Energy and Telecommunications (1985-1995). Retired in 1995. International energy consultant to his former firm and other global companies. A director of Schweitzer-Mauduit International, Inc.

Angus E. Peyton

Partner, Brown & Peyton, attorneys, Charleston, West Virginia

Age 71

Director since 1978

Graduated from Princeton University in 1949 and received his LL.B. from the University of Virginia in 1952. Served as an assistant attorney general of West Virginia (1956-1957), as chairman of the West Virginia Industrial Development Authority, and as West Virginia Commerce Commissioner (1965-1969). Formed his present law firm in 1969. A director of One Valley Bancorp of West Virginia, Inc.

Donald G. Smith

Chairman of the Board, President, Chief Executive Officer and Treasurer of Roanoke Electric Steel Corporation, Roanoke, Virginia

Age 62

Director since 1994

Joined Roanoke Electric Steel Corporation (steel manufacturer) in 1957. Held various positions with Roanoke Electric Steel before being named president and treasurer in 1985, chief executive officer in 1986 and chairman of the board in 1989.

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Linda Gillespie Stuntz

Partner, Stuntz & Davis, P.C., attorneys, Washington, D.C.

Age 43

Director since 1993

Holds an A.B. from Wittenberg University (1976) and J.D. from Harvard Law School (1979). Private practice of law (1979-1981). U.S. House of Representatives, Committee on Energy and Commerce: Associate Minority Counsel, Subcommittee on Fossil and Synthetic Fuels (1981-1986) and Minority Counsel and Staff Director (1986-1987). Private practice of law (1987-1989). U.S. Department of Energy (1989-1993): Acting Deputy Secretary (January 1992-July 1992) and Deputy Secretary (July 1992-January 1993). Returned to the private practice of law in March 1993. A director of Schlumberger Limited. Member, Advisory Council, Electric Power Research Institute.

Kathryn D. Sullivan

President and Chief Executive Officer, COSI Columbus, Columbus, Ohio

Age 46

Director since December 1997

Received her B.S. from the University of California and Ph.D. from Dalhousie University. NASA space shuttle astronaut (1978-1993). Chief Scientist at the National Oceanic and Atmospheric Administration (1993-1996). Became president and chief executive officer of COSI Columbus (science museum) in 1996. U.S. Naval Reserve Officer.

Morris Tanenbaum

Vice President, National Academy of Engineering, Short Hills, New Jersey

Age 69

Director since 1989

Graduated from The Johns Hopkins University in 1949 with a B.A. in chemistry and received a Ph.D. in physical chemistry in 1952 from Princeton University. Joined Bell Telephone Laboratories in 1952 and held various positions with AT&T companies. Became vice chairman of the board of AT&T in 1986 and chief financial officer in 1988. Retired in 1991. A director of Cabot Corporation. A trustee of Massachusetts Institute of Technology, associate trustee of Battelle Memorial Institute, trustee emeritus of The Johns Hopkins University and honorary trustee of The Brookings Institution.

Dr. Draper and Messrs. Peter J. DeMaria and G.P. Maloney are directors of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company (all of which are subsidiaries of AEP with one or more classes of publicly held preferred stock or debt securities) and other subsidiaries of AEP. Dr. Draper and Messrs. DeMaria and Maloney are also directors of AEP Generating Company, a subsidiary of AEP.

Functions of AEP's Board of Directors and Committees

Under New York law, AEP is managed under the direction of AEP's Board of Directors. The Board establishes broad corporate policies and authorizes various types of transactions, but it is not involved in day-to-day operational details. During 1997, the Board held eight regular and two special meetings. The Board has six standing committees, the functions of which are described in the following paragraphs.

The *Audit Committee* consists of Messrs. DesBarres, Duncan, Fri, Hudson and Peyton. The Audit Committee oversees, and reports to the Board concerning, the general policies and practices of AEP and its subsidiaries with respect to accounting, financial reporting, and internal auditing and financial controls. It also maintains a direct exchange of information between the Board and AEP's independent accountants and reviews possible conflict of interest situations involving directors. During 1997 the Audit Committee held four meetings.

The *Committee on Directors* consists of Messrs. Duncan, Fri, Hudson and Kujawa and Ms. Stuntz. The Committee on Directors is responsible for: (i) recommending the size of the Board within the boundaries imposed by the By-Laws; (ii) recommending selection criteria for nominees for election or appointment to the Board; (iii) conducting independent searches for qualified nominees and screening the qualifications of candidates recommended by others; and (iv) recommending to the Board for its consideration one or more nominees for appointment to fill vacancies on the Board as they occur and the slate of nominees for election at the annual meeting. During 1997 the Committee on Directors held two meetings.

The Committee on Directors will consider shareholder recommendations of candidates to be nominated as directors of AEP. All such recommendations must be in writing and addressed to the Secretary of AEP. By accepting a shareholder recommendation for consideration, the Committee on Directors does not undertake to adopt or take any other action concerning the recommendation, or to give the proponent its reasons for not doing so.

The *Corporate Public Policy Committee* consists of Messrs. DesBarres, Duncan, Fri, Hudson, Kujawa, Peyton and Smith, Ms. Stuntz and Drs. Sullivan and Tanenbaum. The Corporate Public Policy Committee is responsible for examining AEP's policies on major public issues affecting the AEP System, as well as established System policies which affect the relationship of AEP and its subsidiaries to their service areas and the general public; for reporting periodically and on request to the Board and providing recommendations to the Board on such policy matters; and for counseling the management of the AEP System on any such policy matters presented to the Committee for consideration and study. During 1997 the Corporate Public Policy Committee held two meetings.

The *Executive Committee* consists of Drs. Draper and Tanenbaum and Mr. Peyton. It is empowered to exercise all the authority of AEP's Board of Directors, subject to certain limitations prescribed in the By-Laws, during the intervals between meetings of the Board. Meetings of the Executive Committee are convened only in extraordinary circumstances. The Executive Committee did not meet during 1997.

The *Finance Committee* consists of Messrs. Kujawa, Peyton and Smith, Ms. Stuntz and Dr. Tanenbaum. The Finance Committee monitors and reports to the Board with respect to the capital requirements and financing plans and programs of AEP and its subsidiaries including, among other things, reviewing and making such recommendations as it considers appropriate concerning the short and long-term financing plans and programs of AEP and its subsidiaries and the implementation of the same. During 1997 the Finance Committee held four meetings.

The *Human Resources Committee* consists of Messrs. DesBarres, Hudson and Smith and Dr. Tanenbaum. The Human Resources Committee is responsible for: (i) reviewing the salaries and other compensation and benefits provided to members of the Board who are officers of AEP or employees of any of its subsidiaries, and recommending to the Board for approval the amount of salary, compensation and benefits to be paid to such persons each year; (ii) reviewing management proposals concerning salaries, compensation and benefits to be paid to senior officers of AEP Service Corporation; (iii) reviewing and making recommendations to the Board with respect to the compensation of directors; (iv) evaluating AEP's hiring, development, promotional and succession planning practices for those management positions described in (ii) above; and (v) periodic review of AEP's overall affirmative action performance. During 1997 the Human Resources Committee held four meetings.

During 1997, except for Dr. Sullivan, no incumbent director attended fewer than 75% of the aggregate of the total number of meetings of AEP's Board of Directors and the total number of meetings held by all Committees on which he or she served. Dr. Sullivan missed one of two Board meetings after she was elected a director, an unscheduled special meeting.

Directors Compensation and Stock Ownership Guidelines

Annual Retainers and Meeting Fees. Directors who are officers of AEP or employees of any of its subsidiaries do not receive any compensation, other than their regular salaries and the accident insurance coverage described below, for attending meetings of AEP's Board of Directors of AEP. The other members of the Board receive an annual retainer of $23,000 for their services, an additional annual retainer of $3,000 for each Committee that they chair, a fee of $1,000 for each meeting of the Board and of any Committee that they attend (except a meeting of the Executive Committee held on the same day as a Board meeting), and a fee of $1,000 per day for any inspection trip or conference (except a trip or conference on the same day as a Board or Committee meeting).

Deferred Compensation and Stock Plan. The Deferred Compensation and Stock Plan for Non-Employee Directors permits non-employee directors to choose to receive up to 100 percent of their annual Board retainer in AEP Shares and/or units that are equivalent in value to AEP Shares ("Stock Units"), deferring receipt by the non-employee director until termination of service or for a period that results in payment commencing not later than five years thereafter. AEP Shares are distributed and/or Stock Units are credited to directors, as the case may be, when the retainer is payable, and are based on the closing price of the AEP Shares on the payment date. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Payment of Stock Units to a director from deferrals of the retainer and dividend credits is made in cash or AEP Shares, or a combination of both, as elected by the director.

Stock Unit Accumulation Plan. The Stock Unit Accumulation Plan for Non-Employee Directors awards 300 Stock Units to each non-employee director as of the first day of the month in which the non-employee director becomes a member of the Board, and annually thereafter, up to a maximum of 3,000 Stock Units for each non-employee director. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Stock Units credited to a non-employee director's account as a result of the annual awards and dividend credits are forfeitable on a pro rata basis for each full month that service as a director is less than 60 months. Stock Units are paid to the director in cash upon termination of service unless the director has elected to defer payment for a period that results in payment commencing not later than five years thereafter.

Insurance. AEP maintains a group 24-hour accident insurance policy to provide a $1,000,000 accidental death benefit for each director (three-year premium was $15,750). The current policy will expire on September 1, 2000, and AEP expects to renew the coverage. In addition, AEP pays each director (excluding officers of AEP or employees of any of its subsidiaries) an amount to provide for the federal and state income taxes incurred in connection with the maintenance of this coverage (approximately $350 annually).

Stock Ownership Guidelines. AEP's Board of Directors considers stock ownership in AEP by management to be of great importance. Such ownership enhances management's commitment to the future of AEP and further aligns management's interests with those of AEP's shareholders. In keeping with this philosophy, the Board has adopted minimum stock ownership guidelines for non-employee directors. The target for each non-employee director is 2,000 shares of AEP Shares and/or Stock Units, with such ownership to be acquired by December 31, 2000 for directors in office on January 1, 1997, and by the end of the fifth year of service for directors joining the Board after this time. For further information as to the guidelines for AEP's executive officers, see the "Board Human Resources Committee Report on Executive Compensation" below under the caption "Stock Ownership Guidelines."

Other Matters

The directors and officers of AEP and its subsidiaries are insured, subject to certain exclusions, against losses resulting from any claim or claims made against them while acting in their capacities as directors and officers. The American Electric Power System companies are also insured, subject to certain exclusions and deductibles, to the extent that they have indemnified their directors and officers for any such losses. Such insurance is provided by Associated Electric & Gas Insurance Services, CNA, Energy Insurance Mutual, The Federal Insurance Company and Great American Insurance Company, effective January 1, 1998 through December 31, 1998, and pays up to an aggregate amount of $150,000,000 on any one claim and in any one policy year. The total annual premium for the five policies is $1,274,413.

Fiduciary liability insurance provides coverage for American Electric Power System companies, their directors and officers, and any employee deemed to be a fiduciary or trustee, for breach of fiduciary responsibility, obligation, or duties as imposed under the Employee Retirement Income Security Act of 1974, as amended. This coverage, provided by The Federal Insurance Company, Zurich Insurance Company and Executive Risk Indemnity, Inc., was renewed, effective July 1, 1997 through June 30, 2000, for a premium of $402,658. It provides $100,000,000 of aggregate coverage with a $500,000 deductible for each loss.

Approval of Auditors

On the recommendation of the Audit Committee, AEP's Board of Directors has appointed the accounting firm of Deloitte & Touche LLP as independent auditors of AEP for the year 1998, subject to approval by the shareholders at the annual meeting. Deloitte & Touche LLP is considered to be the firm best qualified to perform this important function because of its ability and the familiarity of its personnel with AEP's affairs. It and predecessor firms have been AEP's auditors since 1911. Approval of this proposal requires the affirmative vote of holders of a majority of the shares present in person or by proxy at the meeting. The AEP Board of Directors has endorsed this appointment and it is recommending approval of this proposal by the AEP shareholders.

Fees billed by Deloitte & Touche LLP for auditing and other professional services rendered to the Company and its subsidiaries during 1997 were $2,914,000.

Representatives of Deloitte & Touche LLP will be present at the meeting and will have an opportunity to make a statement if they desire to do so. They also will be available to answer appropriate questions.

Executive Compensation

The following table shows for 1997, 1996 and 1995 the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by regulations of the SEC) of AEP at December 31, 1997.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation Salary ($)	Annual Compensation Bonus ($)(1)	Long-Term Compensation Payouts LTIP Payouts($)(1)	All Other Compensation ($)(2)
E. Linn Draper, Jr. — Chairman of the board, president and chief executive officer of AEP and the Service Corporation; chairman and chief executive officer of other subsidiaries	1997	720,000	327,744	951,132	31,620
	1996	720,000	281,664	675,903	31,990
	1995	685,000	236,325	334,851	30,790
Peter J. DeMaria — Controller and director of AEP; vice chairman of the board of the Service Corporation; vice president, controller and director of other subsidiaries	1997	385,000	153,345	391,793	21,570
	1996	360,000	140,832	290,825	21,190
	1995	330,000	113,850	143,829	20,050
G. P. Maloney — Vice president, secretary and director of AEP; vice chairman of the board of the Service Corporation; vice president and director of other subsidiaries	1997	385,000	153,345	391,793	21,570
	1996	360,000	140,832	286,288	21,190
	1995	330,000	113,850	141,582	20,060
William J. Lhota — Executive vice president and director of the Service Corporation; president, chief operating officer and director of other subsidiaries	1997	355,000	141,396	364,436	20,570
	1996	320,000	125,184	263,114	19,690
	1995	300,000	103,500	132,592	19,140
James J. Markowsky — Executive vice president — power generation and director of the Service Corporation; vice president and director of other subsidiaries	1997	325,000	129,447	338,382	18,020
	1996	303,000	118,534	254,535	19,480
	1995	285,000	98,325	126,599	17,515

(1) Amounts in the "Bonus" column reflect payments under the Senior Officer Annual Incentive Compensation Plan (and predecessor Management Incentive Compensation Plan) for performance measured for each of the years ended December 31, 1995, 1996 and 1997. Payments are made in March of the subsequent year. Amounts for 1997 are estimates but should not change significantly.

Amounts in the "Long-Term Compensation" column reflect performance share unit targets earned under the Performance Share Incentive Plan (which became effective January 1, 1994) for the two-, three- and three-year performance periods ending December 31, 1995, 1996 and 1997, respectively. The two-year performance period was a transition performance period.

See below under "Long-Term Incentive Plans — Awards in 1997" and pages 114 and 115 for additional information.

(2) For 1997, includes (i) employer matching contributions under the AEP System Employees Savings Plan: Dr. Draper, $3,400; Mr. DeMaria, $3,306; Mr. Maloney, $4,800; Mr. Lhota, $4,800; and Dr. Markowsky, $3,250; (ii) employer matching contributions under the AEP System Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan: Dr. Draper, $18,200; Mr. DeMaria, $8,244; Mr. Maloney, $6,750; Mr. Lhota, $5,850; and Dr. Markowsky, $6,500;

and (iii) subsidiary companies director fees: Dr. Draper and Messrs. DeMaria and Maloney, $10,020; Mr. Lhota, $9,920; and Dr. Markowsky, $8,270.

Long-Term Incentive Plans — Awards In 1997

Each of the awards set forth below establishes performance share unit targets, which represent units equivalent to shares of AEP Shares, pursuant to AEP's Performance Share Incentive Plan. Since it is not possible to predict future dividends and the price of AEP Shares, credits of performance share units in amounts equal to the dividends that would have been paid if the performance share unit targets were established in the form of AEP Shares are not included in the table.

The ability to earn performance share unit targets is tied to achieving specified levels of total shareholder return ("TSR") relative to the S&P Electric Utility Index. Notwithstanding AEP's TSR ranking, no performance share unit targets are earned unless AEP shareholders realize a positive TSR over the relevant three-year performance period. The Human Resources Committee may, at its discretion. reduce the number of performance share unit targets otherwise earned. In accordance with the performance goals established for the periods set forth below, the threshold, target and maximum awards are equal to 25%, 100% and 200%, respectively, of the performance share unit targets. No payment will be made for performance below the threshold.

Payments of earned awards are deferred in the form of restricted stock units (equivalent to shares of AEP Shares) until the officer has met the equivalent stock ownership target discussed in the Human Resources Committee Report. Once officers meet and maintain their respective targets, they may elect either to continue to defer or to receive further earned awards in cash and/or AEP Shares.

Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Estimated Future Payouts of Performance Share Units Under Non-Stock Price-Based Plan		
			Threshold (#)	Target (#)	Maximum (#)
E. L. Draper, Jr.	7,111	1997-1999	1,778	7,111	14,222
P. J. DeMaria	3,327	1997-1999	832	3,327	6,654
G. P. Maloney	3,327	1997-1999	832	3,327	6,654
W. J. Lhota	3,068	1997-1999	767	3,068	6,136
J. J. Markowsky	2,809	1997-1999	702	2,809	5,618

Retirement Benefits

The American Electric Power System Retirement Plan provides pensions for all employees of AEP System companies (except for employees covered by certain collective bargaining agreements), including the executive officers of AEP. The Retirement Plan is a noncontributory defined benefit plan.

The following table shows the approximate annual annuities under the Retirement Plan that would be payable to employees in certain higher salary classifications, assuming retirement at age 65 after various periods of service.

Pension Plan Table

Highest Annual Earnings	Average Years of Accredited Service						
	15	20	25	30	35	40	45
$ 400,000	$ 93,660	$124,880	$156,100	$187,320	$218,500	$245,140	$271,740
500,000	117,660	156,880	196,100	235,320	274,540	307,790	341,040
600,000	141,660	188,880	236,100	283,320	330,540	370,440	410,340
700,000	165,660	220,880	276,100	331,320	386,540	433,090	479,640
900,000	213,660	284,880	356,100	427,320	498,540	558,390	618,240
1,100,000	261,660	348,880	436,100	523,320	610,540	683,390	756,840
1,300,000	309,660	412,880	516,100	619,320	722,540	808,990	895,440

The amounts shown in the table are the straight life annuities payable under the Retirement Plan without reduction for the joint and survivor annuity. Retirement benefits listed in the table are not subject to any deduction for Social Security or other offset amounts. The retirement annuity is reduced 3% per year in the case of retirement between ages 60 and 62 and further reduced 6% per year in the case of retirement between ages 55 and 60. If an employee retires after age 62, there is no reduction in the retirement annuity.

AEP maintains a supplemental retirement plan which provides for the payment of benefits that are not payable under the Retirement Plan due primarily to limitations imposed by Federal tax law on benefits paid by qualified plans. The table includes supplemental retirement benefits.

Compensation upon which retirement benefits are based, for the executive officers named in the Summary Compensation Table above, consists of the average of the 36 consecutive months of the officer's highest aggregate salary and Senior Officer Annual Incentive Compensation Plan (and predecessor Management Incentive Compensation Plan) awards, shown in the "Salary" and "Bonus" columns, respectively, of the Summary Compensation Table, out of the officer's most recent 10 years of service. As of December 31, 1997, the number of full years of service applicable for retirement benefit calculation purposes for such officers were as follows: Dr. Draper, five years; Mr. DeMaria, 38 years; Mr. Maloney, 42 years; Mr. Lhota, 33 years; and Dr. Markowsky, 26 years.

Dr. Draper has a contract with AEP and AEP Service Corporation which provides him with a supplemental retirement annuity that credits him with 24 years of service in addition to his years of service credited under the Retirement Plan less his actual pension entitlement under the Retirement Plan and any pension entitlement from the Gulf States Utilities Company Trusteed Retirement Plan, a plan sponsored by his prior employer.

Fourteen AEP System employees (including Messrs. DeMaria, Maloney and Lhota and Dr. Markowsky) whose pensions may be adversely affected by amendments to the Retirement Plan made as a result of the Tax Reform Act of 1986 are eligible for certain supplemental retirement benefits. Such payments, if any, will be equal to any reduction occurring because of such amendments. Assuming retirement in 1998 of the executive officers named in the Summary Compensation Table, only Messrs. DeMaria and Maloney would be affected and their annual supplemental benefit would be $491 and $3,847, respectively.

AEP made available a voluntary deferred-compensation program in 1982 and 1986, which permitted certain members of AEP System management to defer receipt of a portion of their salaries. Under this program, a participant was able to defer up to 10% or 15% annually (depending on the terms of the program offered), over a four-year period, of his or her salary, and receive supplemental retirement or survivor benefit payments over a 15-year period. The amount of supplemental retirement payments received is dependent upon the amount deferred, age at the time the deferral election was made, and number of years until the participant retires. The following table sets forth, for the executive officers named in the Summary Compensation Table, the amounts of annual deferrals and, assuming payments commencing at age 65, annual supplemental retirement payments under the 1982 and 1986 programs.

	1982 Program		1986 Program	
Name	Annual Amount Deferred (4-Year Period)	Annual amount of Supplemental Retirement Payment (15-Year Period)	Annual Amount Deferred (4-Year Period)	Annual Amount of Supplemental Retirement Payment (15-Year Period)
P. J. DeMaria	$10,000	$52,000	$13,000	$53,300
G. P. Maloney	15,000	67,500	16,000	56,400

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Board Human Resources Committee Report on Executive Compensation

The Human Resources Committee of AEP's Board of Directors regularly reviews executive compensation policies and practices and evaluates the performance of management in the context of AEP's performance. None of the members of the Committee is or has been an officer or employee of any AEP System company or receives remuneration from any AEP System company in any capacity other than as a director. See page 117.

The Human Resources Committee recognizes that the executive officers are charged with managing a $16 billion multi-state electric utility with international investments during challenging times and with addressing many difficult and complex issues.

AEP's executive compensation program is designed to maximize shareholder value, to support the implementation of AEP's business strategy and to improve both corporate and personal performance. The Committee's compensation policies supporting this program are:

- Pay for performance, motivating both short- and long-term performance. Compensation for short- and long-term performance focuses on meeting specified corporate performance goals and the long-term interests of shareholders, respectively.
- Require a significant amount of compensation for senior executives to be "at risk," variable incentive compensation versus fixed or base pay with much of this risk similar to the risk experienced by other AEP shareholders.
- Enhance AEP's ability to attract, retain, reward, motivate and encourage the development of exceptionally knowledgeable, highly qualified and experienced executives through compensation opportunities.
- Target compensation levels at rates that are reflective of current market practices to maintain a stable, successful management team.

In carrying out its responsibilities, the Committee utilizes independent compensation consultants to obtain information and recommendations relating to changing industry compensation practices and programs.

The Committee also considers management's responses to the impact of increased competition and other significant changes in the rapidly evolving electric utility industry. It is the Committee's opinion that, in this ever-changing environment, Dr. Draper and the senior management team continue to develop and implement strategies effectively to position AEP for the future. This includes AEP's development of unregulated business activities and proposals and actions taken in connection with the industry's transition to competition. Four specific significant initiatives in 1997 were the acquisition of 50% of Yorkshire Electricity, a proposed joint venture with Conoco, developing a national energy trading organization and the Merger Agreement with CSW. The success of these efforts and their benefits to AEP cannot be precisely measured in advance, but the Committee believes they are vital to AEP's long-term success.

Stock Ownership Guidelines. AEP's Board of Directors, upon the Committee's recommendation, underscored the importance of aligning executive and shareholder interests by adopting in December 1994 stock ownership guidelines for senior management participants in the Performance Share Incentive Plan. The Committee and senior management believe that linking a significant portion of an executive's current and potential future net worth to AEP's success, as reflected in the stock price and dividends paid, gives the executive a stake similar to that of AEP's owners and further encourages long-term management for the benefit of those owners.

Under the guidelines, the target ownership of AEP Shares is directly related to the officer's corporate position with the greatest ownership target for the chief executive officer. The target for the CEO is 45,000 shares, which was equivalent to approximately three times his then annual base salary. The targets for the other four officers named in the Summary Compensation Table are 15,000 shares each, equivalent to approximately 1.5 times their then annual base salary. Each officer is expected to achieve the ownership target within a period of five years commencing on January 1, 1995. AEP Shares equivalents earned through the Management Incentive Compensation Plan, Senior Officer Annual Incentive Compensation Plan and Performance Share Incentive Plan, described below, are included in determining compliance with the ownership targets. As of January 1, 1998, Dr. Draper and the other four officers named in the Summary Compensation Table exceeded their respective ownership requirements (see the table on page 117 for actual ownership amounts).

Components of Executive Compensation

Base Salary. When reviewing salaries, the Committee considers pay practices used by other electric utilities and industry in general. In addition, the Committee considers the respective positions held by the executive officers, their levels of responsibility, performance and experience, and the relationship of their salaries to the salaries of other AEP managers and employees.

For compensation comparison purposes, the Human Resources Committee uses the electric utility companies in the S&P Electric Utility Index, which is the peer group used in the Comparison of Five Year Cumulative Total Return graph in this proxy statement. In recognition of AEP's relatively large size and operational complexity, executive officer salary levels are targeted to the second highest quartile (between the 50th and 75th percentiles) of the range of compensation paid by the other electric utilities in this compensation peer group. Base salary levels in 1997 for the CEO and next four most highly compensated executive officers of AEP named in the Summary Compensation Table were within this second highest quartile. In establishing salary levels against that range, the Human Resources Committee considers the competitiveness of AEP's entire compensation package.

Salaries are adjusted, as appropriate, and reviewed annually to reflect individual and corporate performance and consistency with compensation changes within AEP and the compensation peer group of other electric utilities.

The Committee meets without the presence of Dr. Draper, chairman, president and chief executive officer, to evaluate his performance and compensation and reports on that evaluation to the outside directors of the Board. After full discussion, these directors then act on the Committee's recommendation.

Annual Incentive. A variable, performance-based portion of the executive officers' total compensation is paid through the Senior Officer Annual Incentive Compensation Plan ("SOIP"), effective January 1, 1997, which is included in the "Bonus" column in the Summary Compensation Table. The SOIP is the successor to the Management Incentive Compensation Plan ("MICP") for senior officers and is similar in operation and philosophy to the MICP.

The SOIP is intended to motivate and reward senior officers to achieve superior management performance in serving customer needs and creating shareholder value. Each participant is assigned an annual target award expressed as a percentage of annual salary. For 1997, the target awards for Dr. Draper and the other executive officers named in the compensation table were 40% and 35%, respectively. Actual awards can vary from 0-150% of the target award based on performance.

SOIP awards are based entirely on preestablished AEP corporate performance criteria specified in the SOIP. For 1997, these four criteria included (i) total investor return, which reflects stock price and dividends paid, measured relative to the performance of utilities in the S&P Electric Utility Index, (ii) return on stockholder equity, measured relative to the performance of utilities in the S&P Electric Utility Index and on absolute performance, (iii) the extent to which the average price of power sold to retail customers was lower as compared with other utilities in the states which AEP serves and, (iv) effective with the 1997 plan year, "safety performance". For 1997, the performance merited an award of 113.8%. This percentage is an estimate but should not change significantly.

To more closely align the financial interests of the executive officers with AEP's shareholders, SOIP participants may elect to defer their awards, with the deferrals treated as if invested in AEP Shares, although no stock is actually purchased. Dividend equivalents are credited during the deferral period.

Long-Term Incentive. The Performance Share Incentive Plan (the "Plan") provides longer-term, performance-driven, equity incentive award opportunities directly related to shareholder value.

The Plan annually establishes performance share unit targets which are earned based on AEP's subsequent three-year total shareholder returns measured relative to the S&P peer utilities. In 1997, the Committee established targets for Dr. Draper and the other executive officers named in the Summary Compensation Table equivalent to 40% and 35%, respectively, of their then base salaries. The target number of performance share units has been determined after an evaluation of long-term incentive opportunities provided by the S&P peer companies, again targeting the second highest quartile of competitive practice. However, the awards which will ultimately be paid to participants under the Plan for a performance period are not determinable in advance and can range from 0-200% of the target.

The Plan ended a three-year performance period at year end 1997. AEP's total shareholder return for 1995-1997 ranked fourth relative to the S&P peer utilities and, as a result, 185% of the performance share unit targets originally established (and dividend credits) were earned. The associated awards are listed in the Summary Compensation Table.

Similar to the SOIP awards which are deferred, payments of earned awards under the Plan are also deferred in the form of restricted stock units (equivalent to shares of AEP Shares). Such Plan deferrals continue until termination of employment or, if so elected by the recipient, with payments commencing not later than five years thereafter. Once the officers meet and maintain their respective equivalent stock ownership targets discussed above, they may then elect either to continue to defer or to receive further earned Plan awards in cash and/or AEP Shares. Dividend equivalents are credited as though reinvested in additional restricted stock units. The Plan is further described on page 111.

Tax Policy

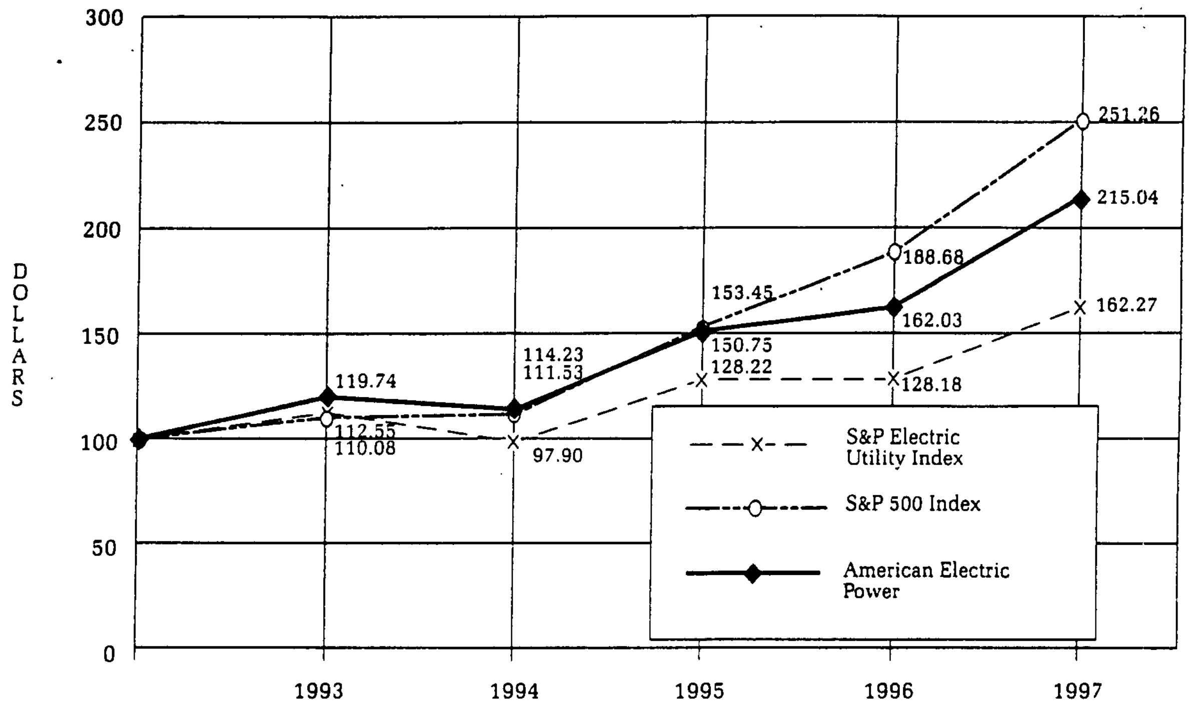
The Committee has considered the impact of Section 162(m) of the Code, which provides a limit on the deductibility of compensation for certain executive officers in excess of $1,000,000 per year. It is the Committee's policy, consistent with sound executive compensation principles and the needs of AEP, to qualify all compensation for deductibility where practicable.

Award payments under the Performance Share Incentive Plan have been structured to be exempt from the deduction limit because they are made pursuant to a shareholder-approved performance-driven plan. Award payments under the SOIP currently are not eligible for the performance-based exemption under the Code. However, since Dr. Draper has deferred his SOIP award to dates past his retirement from AEP, the Committee has not deemed it necessary at this time to qualify compensation paid pursuant to the SOIP for deductibility under Section 162(m). The Committee may decide to do so in the future.

No named officer in the Summary Compensation Table had taxable compensation for 1997 in excess of the deduction limit. The Committee intends to continue to evaluate the impact of this Code provision.

Human Resources
Committee Members
Morris Tanenbaum, Chairman
John P. DesBarres
Lester A. Hudson, Jr.
Donald G. Smith

Comparison of Five Year Cumulative Total Return*
AEP, S&P 500 Index & S&P Electric Utility Index**



Assumes $100 Invested on January 1, 1993 in AEP Common Stock, S&P 500 Index and S&P Electric Utility Index

*Total Return Assumes Reinvestment of Dividends
** Fiscal Year Ending December 31

The total return performance shown on the graph above is not necessarily indicative of future performance.

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Share Ownership of Directors and Executive Officers

The following table sets forth the beneficial ownership of AEP Shares and stock-based units as of January 1, 1998 for all directors as of the date of this Joint Proxy Statement/Prospectus, all nominees to AEP's Board of Directors, each of the persons named in the Summary Compensation Table and all directors and executive officers as a group. Unless otherwise noted, each person had sole voting and investment power over the number of AEP Shares and stock-based units of AEP set forth across from his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	AEP Shares	Stock Units(a)	Total
P. J. DeMaria	7,754(b)(c)(d)(e)	15,932	23,686
J. P. DesBarres	5,000(d)	312	5,312
E. L. Draper, Jr.	7,373(b)(d)	62,857	70,230
R. M. Duncan	2,121	3,169	5,290
R. W. Fri	1,000	937	1,937
L. A. Hudson, Jr.	1,853(e)	3,169	5,022
L. J. Kujawa	300	697	997
W. J. Lhota	15,056(b)(c)(d)	14,827	29,883
G. P. Maloney	5,803(b)(c)(d)	12,715	18,518
J. J. Markowsky	5,126(b)(e)	12,417	17,543
A. E. Peyton	4,819(f)	3,549	8,368
D. G. Smith	2,000	1,258	3,258
L. G. Stuntz	1,500(d)	1,774	3,274
K. D. Sullivan	—	304	304
M. Tanenbaum	1,433	2,839	4,272
All directors and executive officers as a group (15 persons)	146,369(c)(g)	136,756	283,125

(a) This column includes amounts deferred in stock units and held under the Stock Unit Accumulation Plan for Non-Employee Directors, Deferred Compensation and Stock Plan for Non-Employee Directors, Management Incentive Compensation Plan, Senior Officer Annual Incentive Compensation Plan and Performance Share Incentive Plan. Certain of these stock units are subject to forfeiture based on service as a director or length of employment.

(b) Includes the following numbers of share equivalents held in the AEP Employees Savings Plan over which such persons have sole voting power, but the investment/disposition power is subject to the terms of the Savings Plan: Mr. DeMaria, 3,187; Dr. Draper, 2,716; Mr. Lhota, 12,876; Mr. Maloney, 3,436; Dr. Markowsky, 5,074; and all executive officers, 27,289.

(c) Does not include, for Messrs. DeMaria, Lhota and Maloney, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. DeMaria, Lhota and Maloney share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(d) Includes the following numbers of shares held in joint tenancy with a family member: Mr. DeMaria, 462; Mr. DesBarres, 5,000; Dr. Draper, 2,200; Mr. Lhota, 2,180; Mr. Maloney, 2,367; and Ms. Stuntz, 300.

(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Mr. DeMaria, 3,192; Mr. Hudson, 750; and Dr. Markowsky, 19.

(f) Includes 1,500 shares over which Mr. Peyton shares voting and investment power which are held by trusts of which he is a trustee, but he disclaims beneficial ownership of 1,000 of such shares.

(g) Represents less than 1% of the total number of shares outstanding.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act and Section 17(a) of the 1935 Act require AEP's officers and directors to file initial reports of ownership and reports of changes in ownership of AEP Shares and other securities of AEP and its subsidiaries with the SEC and NYSE. Officers and directors are required by SEC regulations to furnish AEP copies of all reports they file. Based solely on AEP's review of the copies of such reports received and written representations from certain reporting persons, AEP notes that during 1997 Angus E. Peyton, a director, did not timely report the acquisition of 354 AEP Shares occurring in April 1997. He reported it in February 1998.

Share Ownership of Certain Beneficial Owners

Set forth below are the only persons or groups known to AEP as of December 31, 1997, with beneficial ownership of 5 percent or more of AEP's Shares.

	AEP Shares	
Name, Address of Beneficial Owners	Amount of Beneficial Ownership	Percent of Class
Sanford C. Bernstein & Co., Inc. 767 Fifth Avenue New York, NY 10153	17,535,763(a)	9.3 %
FMR Corp. 82 Devonshire Street Boston, MA 02109	9,773,663(b)	5.15%

(a) Based on the Schedule 13G filed with the SEC, Sanford C. Bernstein & Co., Inc. reported that it has sole voting power for 10,291,617 shares, shared voting power for 1,807,665 shares, and sole dispositive power for 17,535,763 shares.

(b) The Schedule 13G filed by FMR Corp. included Edward C. Johnson 3d, Chairman of FMR Corp., and Abigail P. Johnson, a director of FMR Corp., as reporting persons. According to the Schedule 13G, FMR Corp. reported that it has sole voting power for 719,263 shares and sole dispositive power for 9,773,663 shares.

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Election of Directors

At the CSW Meeting, three directors will be elected to Class II of the CSW Board for three-year terms expiring at the 2001 annual meeting or at such time as their respective successors are duly elected and qualified, and two directors will be elected to Class III of the CSW Board to fill the remaining one year of the Class III term expiring at the 1999 annual meeting or at such time as their respective successors are duly elected and qualified. Directors will be elected by a plurality of the votes cast at the CSW Meeting.

The CSW Board currently consists of 11 members divided into three classes with staggered terms of office. Class I, Class II and Class III directors' terms will expire at CSW's annual meetings in 2000, 1998 and 1999, respectively. The three nominees for election as Class II directors at the CSW Meeting, Messrs. Brooks, Lawless and Powell, currently serve as Class II directors of the CSW Board. The fourth Class II director, Mr. Glenn Biggs was not nominated for reelection to the CSW Board at the CSW Meeting. Accordingly, the size of the CSW Board will be reduced to 10 after the CSW Meeting. During 1997, Mr. William R. Howell and Dr. Richard L. Sandor were elected to Class III of the CSW Board. In accordance with the CSW Charter, these two directors must stand for election at this annual meeting even though the terms of the Class III directors generally do not expire until the annual meeting in 1999.

Mr. J.C. Templeton retired from the CSW Board in April 1997. Mr. Lloyd D. Ward resigned from the CSW Board on January 1, 1998, Mr. Glenn Files resigned from the CSW Board on January 21, 1998. Each of these three directors were Class III directors prior to their resignation.

The CSW Board has nominated and unanimously recommends that stockholders vote FOR the election of E. R. Brooks, Robert W. Lawless and James L. Powell, as Class II directors, and William R. Howell and Richard L. Sandor, as Class III directors.

Each nominee is presently a director of CSW and has served continuously since the year indicated opposite his/her name below. Each of the nominees has consented to being named as a nominee and to serve as a director of CSW if elected. If, because of events not presently known or anticipated, any nominee is unable to serve or for good cause will not serve, the proxies voted for the election of directors may be voted (at the discretion of the holders of the proxies) for a substitute nominee not named herein.

The following information is given with respect to the nominees for election as directors:

E. R. BROOKS, 60 — **Class II, Director since 1988**

Mr. Brooks has served as Chairman and Chief Executive Officer of CSW since February 1991. He served as CSW's President from February 1991 to July 1997. He is also a member of the Board of Directors of each of CSW's subsidiaries, as well as a Director of Hubbell, Inc. Mr. Brooks is a Trustee of Baylor Health Care Center, Dallas, Texas, and Hardin Simmons University, Abilene, Texas.

ROBERT W. LAWLESS, 61 — **Class II, Director since 1991**

Dr. Lawless served as the President and Chief Executive Officer of Texas Tech University and Texas Tech University Health Sciences Center in Lubbock, Texas from July 1989 through April 1996. He has served as the president of the University of Tulsa since May 1996. He is a member of the Board of Directors of three Salomon Brothers Mutual Funds.

JAMES L. POWELL, 68 **Class II, Director since 1987**

Mr. Powell has been involved in ranching and investments in Ft. McKavett, Texas since prior to 1992. He is a Director of Southwest Bancorp of Sanderson, Texas, a Director and member of the Executive Committee of National Finance Credit Corporation and an Advisory Director of First National Bank, Mertzon, Texas.

WILLIAM R. HOWELL, 62 **Class III, Director since 1997**

Mr. Howell served as Chairman of the Board of J.C. Penney Company from 1983 to January 1997 and also as its Chief Executive Officer from 1983 to January 1995. He is currently Chairman Emeritus of J.C. Penney Company. He has been Chairman of the Board of Trustees of Southern Methodist University since 1996 and serves on the Chairman's Advisory Council of the National Minority Suppliers Development Council. He is a member of the Board of Directors of Exxon Corporation, Warner-Lambert Company, Bankers Trust, Halliburton Company and The Williams Companies, Inc.

RICHARD L. SANDOR, 56 **Class III, Director since 1997**

Dr. Sandor has served as Chairman and Chief Executive Officer of Centre Financial Products Limited since March 1993 and also as Chairman of the Board of Hedge Financial Products, Inc. since May 1997. He is a Board of Director of Center for Sustainable Development in the Americas and is on the board of governors of The School of the Art Institute of Chicago.

The following information is given for continuing directors:

MOLLY SHI BOREN, 54 **Class I, Director since 1991**

Ms. Boren, of Norman, Oklahoma, has been an attorney since prior to 1992 and is a former Special District Judge in Pontotoc County, Oklahoma. She formerly served as a Director of Liberty Bank Corporation and of Pet Incorporated.

DONALD M. CARLTON, 60 **Class I, Director since 1994**

Mr. Carlton served as the President and Chairman of Radian Corporation, an engineering and technology firm, from 1969 through December 1995. In January 1996 he was named President and Chief Executive Officer of Radian International LLC. He is a member of the Board of Directors of Concert Investment Series Funds and National Instruments.

T. J. ELLIS, 55 **Class I, Director since 1996**

Mr. Ellis is Chairman and Chief Executive Officer of SEEBOARD and has served in such capacity since January 1996. Previously he served as the Chief Executive Officer of SEEBOARD for more than the past five years. He currently serves as a director of CSW UK Finance Company, CSW Investments, Sussex Chamber of Commerce Training and Enterprise and The Brighton West Pier Trust.

THOMAS V. SHOCKLEY, III, 52 **Class I, Director since 1991**

Mr. Shockley was elected President and Chief Operating Officer of CSW in July 1997. He joined CSW as Senior Vice President in January 1990, and became an Executive Vice President in September of that same year. In addition, he served as Chief Executive Officer of CSW's subsidiary, Central and South West Services, Inc., from October 1992 to December 1993. Mr. Shockley continues to serve as a Director of each of CSW's non-electric subsidiaries.

JOE H. FOY, 71 **Class III, Director since 1974**

Mr. Foy served as a partner of the law firm of Bracewell & Patterson, Houston, Texas until his retirement in 1993. He is currently a member of the Board of Directors of Enron Corporation.

Security Ownership of Management

The following table shows securities beneficially owned as of December 31, 1997 by each director and nominee, certain executive officers and all directors and executive officers as a group. Share amounts shown in this table include options exercisable within 60 days after December 31, 1997, restricted stock, CSW Shares credited to thrift plus accounts and all other CSW Shares beneficially owned by the listed persons.

Name	CSW Shares(1)(2)
Glenn Biggs	19,211
Molly Shi Boren	3,119
E.R. Brooks	131,529
Donald M. Carlton	8,230
T. J. Ellis	7,694
Glenn Files	42,269
Joe H. Foy	10,717
T.M. Hagan	13,625
William R. Howell	1,000
Robert W. Lawless	3,074
Venita McCellon-Allen	6,528
Ferd. C. Meyer, Jr.	46,480
James L. Powell	4,211
Glenn D. Rosilier	68,071
Richard L. Sandor	—
Thomas V. Shockley, III	68,329
Lloyd D. Ward	2,157
All of the above and other officers as a group (CSW directors and officers)	486,165

(1) Shares for Ms. McCellon-Allen, Messrs. Brooks, Files, Hagan, Meyer, Rosilier, Shockley, and CSW directors and officers include 1,125, 12,225, 4,500, 1,125, 5,700, 5,700, 7,275, and 42,150 shares of restricted stock, respectively. These individuals currently have voting power, but not investment power, with respect to these shares. The above shares also include 1,934, 65,175, 23,653, 8,484, 32,889, 32,889, 42,231, and 239,258 CSW Shares underlying immediately exercisable options held by Ms. McCellon-Allen, Messrs. Brooks, Files, Hagan, Meyer, Rosilier, Shockley, and CSW directors and officers, respectively.

(2) All of the share amounts represent less than one percent of the outstanding CSW Shares.

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Security Ownership of Certain Beneficial Owners

Set forth below are the only persons or groups known to CSW as of December 31, 1997, with beneficial ownership of 5 percent or more of CSW's Shares.

	CSW Shares	
Name, Address of Beneficial Owners	Amount of Beneficial Ownership	Percent of Class
Mellon Bank Corporation and subsidiaries .... One Mellon Bank Center Pittsburgh, PA 15258	12,196,127(1)	6%

(1) Mellon Bank Corporation and its subsidiaries, including Mellon Bank, N.A., which acts as trustee of an employee benefit plan of CSW, reported that they exercise sole voting power as to 11,022,435 shares and shared voting power as to 11,022,435 shares.

Other Information Regarding the CSW Board

Nominees for directorships are recommended by the Nominating Committee of the CSW Board and are nominated by the CSW Board on the basis of their qualifications, including training, experience, integrity and independence of mind, to render service to CSW. CSW's Bylaws generally provide that CSW shall not elect or propose for election as a director any non-employee who will have attained the age of 70 (72 for persons who served as directors and were at least 60 years of age on October 12, 1987) at the date of such election or proposed election. Federal law restricts the extent to which CSW may have interlocking directorates with other companies.

The number of directors constituting the entire CSW Board may not be less than nine nor more than fifteen, as may be fixed from time to time by resolution adopted by a majority of the entire CSW Board. The size of the CSW Board is currently fixed at 12. No decrease in the number of directors on the CSW Board may shorten the term of any incumbent director. The majority of the CSW Board may adopt a resolution to increase the number of directors to not more than fifteen and may elect a new director or directors to fill any such newly created directorship. Similarly, vacancies occurring on the CSW Board for any reason may be filled by majority vote of the remaining directors. Any such CSW Board-elected director will hold office until CSW's next annual meeting of stockholders and the election and qualification of a successor.

Under the CSW Charter, any director may be removed from office by the stockholders of CSW only for cause and only by the affirmative vote of the holders of at least 80 percent of the voting power of the outstanding CSW Shares.

Meetings and Compensation of the CSW Board

The CSW Board held 6 regular meetings and 8 special meetings during 1997. Directors who are not also officers and employees of CSW receive annual cash directors' fees of $12,000 for serving on the CSW Board and a fee of $1,250 per day plus expenses for each meeting of the CSW Board or committee attended. In addition, under the CSW Directors' Plan each non-employee director receives an annual award of 600 phantom stock shares on the fourth Wednesday of January during their term of office. Such phantom stock shares vest at such time as a director ceases to be a member of the CSW Board and are then converted into CSW Shares on a one-for-one basis. The CSW Board has standing Policy, Audit, Executive Compensation, Nominating and Corporate Strategy Review Committees. Chairmen of the Audit, Corporate Strategy Review, Executive Compensation, and Nominating Committees receive annual fees of $6,000, $6,000, $3,500 and $3,500, respectively, to be paid in cash in addition to regular directors' and meeting fees. Committee chairmen and committee members who are also officers and employees of CSW receive no annual director's, chairman's or meeting fees.

CSW maintains a memorial gift program for all of its current directors, directors who have retired since 1992 and certain executive officers. There are 14 current directors and executive officers and 13 retired directors and officers eligible for the memorial gift program. Under this program, CSW will make donations in a director's or executive officer's name to up to three charitable organizations in an aggregate of $500,000, payable by CSW upon such person's death. CSW maintains corporate-owned life insurance policies to fund the program. The annual premiums paid by CSW are based on pooled risks and averaged $15,803 per participant for 1997, $16,402 per participant for 1996, and $16,367 per participant for 1995.

Non-employee directors are provided the opportunity to enroll in a medical and dental program offered by CSW. This program is identical to the employee plan and directors who elect coverage pay the same premium as active employee participants in the plan. If a non-employee director terminates his service on the board with ten or more years of service and is over seventy years of age, that director is eligible to receive retiree medical and dental benefits coverage from CSW.

Non-employee directors are provided the opportunity to participate in the Central and South West Deferred Compensation Plan for Directors. The plan allows participants to defer up to $20,000 of board and committee fees. Participants receive a ten-year annuity, based on the amount deferred, beginning at the participants normal retirement date from the Board.

During 1997, CSW retained Mr. Glenn Biggs, a current member of the CSW Board, under an agreement to pursue special business development activities in Mexico on behalf of CSW. For the year ended December 31, 1997, CSW paid Mr. Biggs $120,000 pursuant to this agreement. Effective March 18, 1998, Mr. Biggs resigned his position as a director of CSW. Mr. Biggs had not previously been nominated for reelection to the CSW Board. In connection with his resignation, Mr. Biggs' consulting arrangement was terminated. CSW and Mr. Biggs entered into an agreement pursuant to which Mr. Biggs was paid, a lump sum for, among other things, his benefit under certain compensation plans and to pay his director and CSW Board committee fees through May 1998 and his consulting fees through March 1998. Pursuant to that agreement, Mr. Biggs and his spouse are also entitled to continued medical and dental coverage under the CSW Medical Plan for Outside Directors and CSW has agreed to maintain the memorial gift program for Mr. Biggs.

All current directors attended more than 75 percent of the total number of meetings held by the Board and each committee on which such directors served in 1997, except for Mr. Ward who attended 57 percent of the total meetings.

CSW Board Committees

Policy Committee. The Policy Committee, currently consisting of Messrs. Brooks (Chairman), Foy, Lawless and Powell, held 9 meetings in 1997. The Policy Committee reviews and makes recommendations to the CSW Board concerning major policy issues, considers the composition, structure and functions of the CSW Board and its committees and reviews existing corporate policies and recommends changes when appropriate. The Policy Committee has authority to act as and on behalf of the CSW Board when the full CSW Board is not in session.

Audit Committee. The Audit Committee, currently consisting of Ms. Boren and Messrs. Carlton, Lawless (Chairman), Powell and Sandor, held 4 meetings in 1997. The Audit Committee recommends to the CSW Board the independent public accountants to be selected; discusses with the internal auditors and independent public accountants the overall scope, plans and results of their audits, and their evaluations of internal controls and the overall quality of CSW's accounting and financial reporting practices; facilitates any private communication with the committee desired by the internal auditors or independent public accountants; discusses with management, internal auditors and the independent public accountants CSW's accounting and financial reporting principles and policies; monitors the program to ensure compliance with CSW's business ethics policy; and may direct and supervise an investigation into any significant matter brought to its attention within the scope of its duties.

Executive Compensation Committee. The Executive Compensation Committee, currently consisting of Ms. Boren and Messrs. Foy (Chairman), Howell, Lawless, and Sandor, held 6 meetings in 1997. The Executive Compensation Committee determines the executive compensation philosophy of CSW, reviews benefit programs and management succession programs, sets the salaries for the executive officers of CSW and reviews and recommends salaries for the chief executive officers of CSW's principal subsidiaries.

Nominating Committee. The Nominating Committee, currently consisting of Messrs. Carlton, Foy, Howell and Powell (Chairman), held 5 meetings in 1997. The Nominating Committee reviews candidates for election to the CSW Board and recommends qualified candidates to fill existing vacancies or newly created directorships. The Nominating Committee welcomes stockholder suggestions for CSW Board nominations. Such suggestions should be directed to Mr. Brooks, Chairman, President and Chief Executive Officer, who will forward them to the Nominating Committee.

Corporate Strategy Review Committee. The Corporate Strategy Review Committee currently consisting of Messrs. Carlton, Foy (Chairman), Howell, Lawless and Powell, held 8 meetings in 1997. The primary purposes of the Corporate Strategy Review Committee, which is comprised exclusively of nonemployee directors, are to assist and advise the CSW Board in evaluating various strategic alternatives available to CSW. Specifically, the duties of the Corporate Strategy Review Committee include overseeing the integrity of the evaluation process and keeping the CSW Board informed on a timely basis, as well as recommending to the CSW Board a course of action which the Committee determines is in the best interests of CSW and its stockholders. The committee is also responsible for directing the negotiation by management of specific terms and conditions relating to strategic transactions including the Merger.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act and Section 17(a) of the 1935 Act require CSW's officers and directors, and persons who beneficially own more than ten percent of CSW's Shares to file reports of ownership and changes in ownership with the SEC and NYSE. Officers, directors and greater-than-ten-percent stockholders are required by SEC regulation to furnish CSW copies of all Section 16(a) reports they file. Based solely on CSW's review of the copies of such forms received and written representations from certain reporting persons, CSW believes that during 1997 all such filing requirements applicable to its officers, directors and greater-than-ten-percent stockholders were met with the exception of Stephen J. McDonnell (who due to a reorganization went out of office as Treasurer effective May 1996 and was not elected Vice President, Mergers and Acquisitions until April 1997) who did not file a Form 5 for the year ending December 31, 1996, reporting his year end ownership in the CSW Retirement Savings Plan and CSW Dividend Reinvestment Plan. Following this inadvertent delinquency, Mr. McDonnell filed the proper Form 5 with the SEC.

Compensation Committee Interlocks and Insider Participation

No member of the Executive Compensation Committee of the CSW Board served as an officer or employee of CSW or any of its subsidiaries during or prior to 1997. No executive officer of CSW serves or has served on the Executive Compensation Committee during or prior to 1997. No executive officer of CSW serves or has served as a director of another company, one of whose executive officers serves as a member of the Executive Compensation Committee or as a director of CSW, during or prior to 1997.

Approval Of Appointment Of Independent Public Accountants

The Audit Committee of the CSW Board, which is composed entirely of non-employee directors, has selected Arthur Andersen LLP as the independent public accountants to audit the consolidated financial statements of CSW and its consolidated subsidiaries for the year ending December 31, 1998. The CSW Board has endorsed this appointment and it is being presented to the CSW stockholders for approval.

Arthur Andersen LLP has audited the consolidated financial statements of CSW and its subsidiaries for many years. CSW has been advised by Arthur Andersen LLP that neither it nor any member or employee thereof has any direct financial interest or any material indirect financial interest in CSW or any of its subsidiaries in any capacity.

During the year ended December 31, 1997, Arthur Andersen LLP provided both audit and non-audit services to CSW and its subsidiaries. These audit services included: (1) regular examination of the consolidated financial statements of CSW, including work relating to quarterly reviews, SEC filings and consultation on accounting and financial reporting matters; (2) audit of the financial statements of certain subsidiary companies to meet statutory or regulatory requirements; and (3) examination of the financial statements of various employee benefit plans of CSW and its subsidiaries. Nonaudit services provided by Arthur Andersen LLP included income tax consulting, employee benefit advisory services, economic consulting and other financial consulting services.

The financial statements of SEEBOARD for calendar year 1997 and prior years have been audited by KPMG Peat Marwick, which firm is expected to be engaged to audit such financial statements for the year ending December 31, 1998. Andersen Consulting, which is an affiliate of Arthur Andersen LLP, provides information technology services to SEEBOARD.

All significant audit and nonaudit services provided by Arthur Andersen LLP and Andersen Consulting are approved by the Audit Committee which gives due consideration to the potential effect of nonaudit services on auditor independence.

One or more representatives of Arthur Andersen LLP will be present at the CSW Meeting, will have an opportunity to make a statement if he or she desires to do so and will be available to respond to appropriate questions.

Ratification of the appointment of Arthur Andersen LLP to audit the consolidated financial statements of CSW for the year ending December 31, 1998 requires the affirmative vote of a majority of the votes cast by the holders of CSW Shares present in person or by proxy at the CSW Meeting. An abstention from voting will have the same effect as votes cast against such proposal. An abstention will be included in computing the number of shares present for purposes of determining the presence of a quorum at the CSW Meeting. If the resolution does not pass, the selection of independent public accountants will be reconsidered by the Audit Committee and the CSW Board.

The CSW Board recommends a vote FOR the proposal to ratify the appointment of Arthur Andersen LLP as independent public accountants of CSW for fiscal year 1998. Proxies received by the CSW Board will be so voted unless stockholders specify in their proxies a contrary choice.

Transaction Of Other Business

At the date hereof, the management of CSW knows of no other business to come before the CSW Meeting. If any other business is properly presented at the CSW Meeting, the proxies will be voted in respect thereof in the discretion of the person or persons voting them.

Executive Compensation

Executive Compensation Committee Report

CSW's executive compensation program has as its foundation the following objectives:

- Maintaining a total compensation program consisting of base salary, performance incentives and benefits designed to support the corporate goal of providing superior value to CSW stockholders and customers;
- Providing comprehensive programs which serve to facilitate the recruitment, retention and motivation of qualified executives; and
- Rewarding key executives for achieving financial, operating and individual objectives that produce a corresponding and direct return to CSW's stockholders in both the long-term and the short-term.

The Executive Compensation Committee which consists of six independent outside directors, has designed CSW's executive compensation programs around a strong pay-for-performance philosophy. The Executive Compensation Committee strives to maintain competitive levels of total compensation as compared to peers in the utility industry.

Each year, the Executive Compensation Committee conducts a comprehensive review of CSW's executive compensation programs. The Executive Compensation Committee is assisted in these efforts by an independent consultant and by CSW's internal staff, who provide the Executive Compensation Committee with relevant information and recommendations regarding the compensation policies, programs and specific compensation practices. This review is designated to ensure that the programs are in place to enable CSW to achieve its strategic and operating objectives and provide superior value to its stockholders and customers, and to document CSW's relative competitive position.

The Executive Compensation Committee reviews a comparison of CSW's compensation programs with those offered by comparable companies within the utility industry. For each component of compensation, as well as total compensation, the Executive Compensation Committee seeks to ensure that CSW's level of compensation for CSW's expected level of performance approximates the average or mean for executive officers in similar positions at comparable companies. In most years, this means that the level of total compensation for expected performance will be near the average for comparable companies. Performance above or below expected levels is reflected in a corresponding increase or reduction in the incentive portion of the compensation program.

The amounts of each of the primary components of executive compensation—salary, annual incentive plan awards and long-term incentive plan awards—will fluctuate according to individual, business unit, and/or corporate performance. Corporate performance for these purposes is measured against a peer group of selected companies in the utility industry (the "Utility Peer Group"). The Utility Peer Group consists of the companies listed in the S&P Electric Utility index as well as large regional competitors. The Executive Compensation Committee believes that using the S&P Electric Utility index provides an objective measure to compare performance benchmarks appropriate for compensation purposes.

CSW's executive compensation program includes several components serving long and short-term objectives. CSW provides its senior executive officers with benefits under the SERP and all executive officers with certain executives perquisites (as noted elsewhere in this Joint Proxy Statement/Prospectus.) In addition, CSW maintains for each of its executive officers a package of benefits under its pension and welfare benefit plans that are generally provided to all employees, including group health, life, disability and accident insurance plans, tax-advantaged reimbursement accounts, a defined benefit pension plan and the 401(k) savings plan.

The following describes the relationship of compensation to performance for the principal components of executive officer compensation:

Base Salary: Each executive officer's corporate position is matched to a comparable position within the utility Industry and is valued at the 50th percentile market level. In some cases, these positions are common in both the utility industry as well as general industry. In these cases, comparisons are made to both markets. Once these market values are determined, the position is then evaluated based on the position's overall contribution to corporate goals. This internal weighting is combined with the value the market places on the associated job responsibilities and a salary is assigned to that position. Each year the assigned values are reviewed against market conditions, including compensation practices in the Utility Peer Group, inflation, and supply and demand in the labor markets. If these conditions change significantly there may be an adjustment to base salary. Finally, the results of the executive officers' performance over the past year becomes part of the basis of the Executive Compensation Committee's decision to approve, at its discretion, base salaries of executive officers. After a review of the data and other factors influencing corporate results, the salaries of the Chairman and his direct reports were not adjusted during 1997.

Incentive Programs—General: The executive incentive programs are designed to strike an appropriate balance between short-term accomplishments and CSW's need to effectively plan for and perform over the long-term.

Incentive Programs—Annual Incentive Plan: The Central and South West Corporation Annual Incentive Plan (the "AIP") is a short-term bonus plan rewarding annual performance. AIP awards are determined under a formula that directly ties the amount of the award with levels of achievement for specific individual, business unit and corporate performance. The amount of an executive officer's AIP award equals the sum of the corporate and business unit results times their individuals rating times their target award. In addition, the executive's award calculation is weighted 80 percent on corporate results and 20 percent on business unit results. The award can vary from 0 to a maximum of 150 percent of target.

The corporate performance is currently determined by two equally weighted measures—earnings per share and cash flow. Threshold, target and exceptional levels of performance are set by the Executive Compensation Committee in the first quarter of each year. The Executive Compensation Committee considers both historic performance and budgeted or expected levels of performance in setting these targets.

Performance for a given business unit represents the weighted average of performance indices that measure the achievement of specific financial and/or operational goals that are set and weighted at the beginning of the year for that business unit.

The individual performance represents the average of results achieved on several individual goals and a subjective evaluation of overall job performance. Although individual performance goals do not repeat corporate performance measures, these goals are constructed to support departmental, work team or business unit performance which links to corporate performance goals or initiative. If an individual fails to achieve a minimum threshold performance level on individual performance goals, that individual does not earn an AIP award for that year.

Target awards for executive officers have been fixed at 50 percent of salary for the chief executive officer, 45 percent of salary for senior vice presidents, and business unit presidents and 35 percent of salary for other officers. The corresponding maximum AIP award that can be earned by the executive based on position is 1.5 times the target award. These targets are established by a review of competitive practice among the Utility Peer Group.

Performance under the AIP is measured or reviewed by each executive officer's superior officer, or in the case of the chief executive officer by the Executive Compensation Committee, with the assistance of internal staff. The results are reviewed and are subject to approval by the Executive Compensation Committee. Under the terms of the AIP, the Executive Compensation Committee in the exercise of its discretion, may vary corporate or company performance measures in the form of payment for AIP awards from year-to-year prior to establishing the awards, including payment in cash or restricted stock, as determined by the Executive Compensation Committee.

In 1997, AIP awards were determined based on the corporate performance index, the business unit company performance index and the individual performance index. As permitted by the AIP, the Executive Compensation Committee granted a limited number of awards to recognize key individuals who provided vision and strategic leadership.

Incentive Programs—Long-Term Incentive Plan: Amounts realized by CSW's executive officers under awards made pursuant to the CSW Incentive Plan depend entirely upon corporate performance. The Executive Compensation Committee selects the form and amount of CSW Incentive Plan awards based upon its evaluation of which vehicles are best positioned to serve as effective incentives for long-term performance.

Since 1992, the Executive Compensation Committee has established CSW Incentive Plan awards in the form of performance shares. These awards provide incentives both for exceptional corporate performance and retention. Each year, the Compensation Committee has set a target award of a specified dollar amount for each awardee based on a percentage of salary. The dollar amount corresponding to the target award is divided by the per share market price of CSW's common stock on the date the award is established to derive the number of shares of such stock that will be issued if target performance is achieved by CSW.

The payout of such an CSW Incentive Plan award is based upon a comparison of CSW's total stockholder return over a three-year period, or "cycle," against total stockholder returns of utilities in the Utility Peer Group over the same three-year period. Total stockholder return is calculated by dividing (i) the sum of (A) the cumulative amount of dividends per share for the three-year period, assuming full dividend reinvestment, and (B) the change in share price over the three-year period, by (ii) the share price at the beginning of the three-year period. If CSW's total stockholder return for a cycle falls in one of the top three quartiles of similarly calculated total stockholder returns achieved at companies in the Utility Peer Group, CSW will make a payout to participants for the three-year cycle then ending. First, second and third quartile performance will result in payouts of 150 percent, 100 percent and 50 percent of target, respectively. Performance in the fourth quartile yields no payout under the CSW Incentive Plan.

Each year since the inception of the CSW Incentive Plan, a new three-year performance cycle has been established. In January 1997, the Executive Compensation Committee evaluated the 1994-1996 cycle performance under the CSW Incentive Plan and because results were below the threshold for a payout, no awards were granted. In January 1998, the Committee reviewed total stockholder return results for the period covering 1995-1997, and because performance was in the third quartile, granted restricted stock awards at 50 percent of target.

CSW from time to time has also granted stock options and restricted stock under the CSW Incentive Plan. Stock options and restricted stock are granted at the discretion of the Executive Compensation Committee. Stock options, once vested, allow grantees to buy specified numbers of shares of CSW common stock at a specified stock price, which to date has been the market price on the date of grant. In determining grants to date, the Executive Compensation Committee has considered both the number and value of options granted by companies in the Utility Peer Group with respect to both the number and value of options awarded by CSW, and the relative amounts of other long-term incentive awards at CSW and such peers. The executive officers' realization of any value on the options depends upon stock appreciation. In May 1997, a stock option grant was approved at the market price of $20.75 per share to provide the opportunity for more equity ownership and to provide immediate focus to our executives on CSW strategic initiatives. No executive officer owns in excess of one percent of CSW's common stock. Further, the amounts of CSW Incentive Plan awards are measured against similar practices of other companies in the Utility Peer Group.

Tax Considerations: Section 162(m) of the Code generally limits CSW's federal income tax deduction for compensation paid in any taxable year to any one of the five highest paid executive officers named in CSW's proxy statement to $1 million. The limit does not apply to specified types of payments, including, most significantly, payments that are not includible in the employee's gross income, payments made to or from a tax-qualified plan, and compensation that meets the Code's definition of performance-based compensation. Under the Code, the amount of a performance-based incentive award must be based entirely on an objective formula, without any subjective consideration of individual performance, to be considered performance-based.

The Executive Compensation Committee has carefully considered the impact of this law. At this time, the Executive Compensation Committee believes it is in CSW's and stockholder's best interests to retain the subjective determination of individual performance under the AIP. Consequently, payments under the AIP, if any, to the named executive officers may be subject to the limitation imposed by section 162(m) of the Code. In 1997, stockholders approved a restatement and requalification of the CSW Incentive Plan for purposes of satisfying Section 162(m).

Rationale for CEO Compensation

In 1997, Mr. Brooks' compensation was determined as described above for all of CSW's executive officers.

Mr. Brooks' annual salary is currently $700,000. The Executive Compensation Committee reviewed Mr. Brooks' salary as a part of its overall annual review of executive compensation. His salary is based on market information for similar positions as well as salaries of chief executive officers at comparable regional utilities (not limited to the Utility Peer Group).

Mr. Brooks' target AIP award for 1997 was 50 percent of his salary. As permitted by the AIP, for 1997, the Executive Compensation Committee approved an award in the amount of $450,000 to recognize Mr. Brooks' significant vision and strategic leadership.

After a review of the results of the 1995-1997 cycle of the CSW Incentive Plan, the Executive Compensation Committee approved an award in the amount of 8,157 shares of restricted stock recognizing total shareholder return performance in the third quartile, or fifty percent of target, which vest fifty percent in January 1999 and fifty percent in January 2000.

In 1997 the Executive Compensation Committee established Mr. Brooks' target award for the CSW Incentive Plan for the 1997-1999 cycle of $490,000 to be paid in shares of restricted stock in 1999 if performance measures are met. Mr Brooks' target amount was derived by reference to the number and value of grants to chief executive officers at comparable companies.

EXECUTIVE COMPENSATION COMMITTEE

Joe H. Foy, Chairman
Molly Shi Boren
William R. Howell
Robert W. Lawless
Richard L. Sandor
Lloyd D. Ward

Cash and Other Forms of Compensation. The following table sets forth the aggregate cash and other compensation for services rendered for the fiscal years of 1997, 1996, and 1995 paid or awarded by CSW to its chief executive officer and each of the four most highly compensated executive officers (the "Named Executive Officers").

Summary Compensation Table

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Other Annual Compensation ($)	Restricted Stock Award(s) ($)(1)(2)	Securities Underlying Options/ SARs(#)	CSW Incentive Plan Payouts ($)	All Other Compensation ($)(3)
E.R. Brooks	1997	699,999	375,200	14,723	—	65,000	—	23,757
Chairman and Chief	1996	657,692	374,354	22,267	417,688	—	—	23,992
Executive Officer	1995	628,847	162,739	25,149	—	—	—	23.956
T.V. Shockley, III	1997	490,000	215,662	4,325	—	41,000	—	23,757
President and Chief	1996	435,212	242,565	10,746	248,563	—	—	21,742
Operating Officer	1995	406,870	105,448	8,441	—	—	—	21.706
Glenn Files	1997	374,999	143,099	8,534	—	31,000	—	23,757
Senior Vice President,	1996	331,135	44,860	66.415	153.750	—	—	23,992
Electric Operations	1995	266,223	85,048	19.144	—	—	—	23,117
Ferd. C. Meyer, Jr.	1997	345,051	157,157	3,950	—	29,000	—	21.307
Executive Vice President	1996	345.051	209,898	8.910	194,750	—	—	21,742
and General Counsel	1995	336,547	86,444	12,354	—	—	—	21,706
Glenn D. Rosilier	1997	334,751	161.055	3.594	—	28,000	—	23,757
Executive Vice President	1996	334.751	209.898	10,331	194,750	—	—	23,992
and Chief Financial Officer	1995	326,500	86.444	6.706	—	—	—	23,019

(1) Amounts in these columns are paid or awarded in a calendar year for performance in a preceding year.

(2) Grants of restricted stock are administered by the Executive Compensation Committee of the CSW Board of Directors, which has the authority to determine the individuals to whom and the terms upon which restricted stock grants, including the number of underlying shares, shall be made. The awards reflected in this column all have four-year vesting periods with 25% vesting on the first, second, third and fourth anniversary dates of the award. Upon vesting, CSW Shares are re-issued without restrictions. The individual receives dividends and may vote shares of restricted stock, even before they are vested. The amount reported in the table represents the market value of the shares at the date of grant. As of December 31, 1997, the aggregate restricted stock holdings of each of the Named Executive Officers were:

	Restricted Stock Held at December 31, 1997	Market Value at December 31, 1997
E. R. Brooks	12,225	$330,839
T. V. Shockley	7,275	$196,880
Glenn Files	4,500	$121,781
Ferd. C. Meyer, Jr.	5,700	$154,256
Glenn Rosilier	5,700	$154,256

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(3) Amounts shown in this column consist of (i) the annual employer matching payments to CSW's Retirement Savings Plan, (ii) premiums paid per participant for personal liability insurance and (iii) average amounts of premiums paid per participant in those years under CSW's memorial gift program. See "—Meetings and Compensation of the CSW Board of Directors" for a description of CSW's memorial gift program.

Option/SAR Grants. Shown below is information on grants of stock options made in 1997 pursuant to the CSW Incentive Plan to the Named Executive Officers. No stock appreciation rights were granted in 1997.

CSW Option/SAR Grants In 1997(1)

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of CSW Stock Price Appreciation for Option Terms(3)	
Name	Number of CSW Securities Underlying Options/SARs Granted(#)(2)	% of Total Options/SARs Granted to Employees In Fiscal Year	Exercise or Base Price ($/Sh)	Expiration Date	5%($)	10%($)
E. R. Brooks	65,000	9.4	20.750	5/23/2007	849,713	2,144,513
T. V. Shockley, III	41,000	6.0	20.750	5/23/2007	535,973	1,352,693
Glenn Files	31,000	4.5	20.750	5/23/2007	405,248	1,022,768
Ferd. C. Meyer, Jr.	29,000	4.2	20.750	5/23/2007	379,103	956,753
Glenn D. Rosilier	28,000	4.1	20.750	5/23/2007	366,030	923,790

(1) The stock option plans are administered by the Executive Compensation Committee of the CSW Board of Directors, which has the authority to determine the individuals to whom and the terms upon which option and SAR grants shall be made.

(2) All options were granted on May 23, 1997, and are first exercisable 12 months after the grant date, with one-third of the shares becoming exercisable at that time and with an additional one third of the aggregate becoming exercisable on each of the next two anniversary dates.

(3) The annual rates of appreciation of 5% and 10% are specifically required by SEC disclosure rules and in no way guarantee that such annual rates of appreciation will be achieved by CSW nor should this be construed in any way to constitute any representation by CSW that such growth will be achieved.

Option/SAR Exercises and Year-End Value Table. Shown below is information regarding option/SAR exercises during 1997 and unexercised options/SARs at December 31, 1997 for the Named Executive Officers.

Aggregated Option/SAR Exercises in 1997 and Fiscal Year-End Option/SAR Values

Name	Shares Acquired on Exercise(#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at Year-End Exercisable/ Unexercisable	Value of In-the-Money Options/SARs at Year-End Exercisable/ Unexercisable(1)
E. R. Brooks	—	—	65,175/65,000	9,007/410,313
T. V. Shockley, III	—	—	42,231/41,000	5,837/258,813
Glenn Files	—	—	23,653/31,000	5,593/195,688
Ferd. C. Meyer, Jr.	—	—	32,889/29,000	4,547/183,063
Glenn D. Rosilier	—	—	32,889/28,000	4,547/176,750

(1) Calculated based upon the difference between the closing price of CSW's Shares on the NYSE on December 31, 1997 ($27.0625 per share) and the exercise price per share of the outstanding unexercisable and exercisable options ($20.750, $24.813 and $29.625, as applicable).

Long-Term Incentive Plan Awards in 1997. The following table shows information concerning awards made to the Named Executive Officers during 1997 under the CSW Incentive Plan:

Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts under Non-Stock Price Based Plans		
			Threshold ($)	Target ($)	Maximum ($)
E. R. Brooks	—	2 years	—	490,000	735,000
T. V. Shockley, III	—	2 years	—	294,000	441,000
Glenn Files	—	2 years	—	225,000	337,500
Ferd. C. Meyer, Jr.	—	2 years	—	207,030	310,545
Glenn D. Rosilier	—	2 years	—	200,850	301,275

Payouts of the awards are contingent upon CSW's achieving a specified level of total stockholder return, relative to the S&P Electric Index, for a three-year period, or cycle, and exceeding a certain defined minimum threshold. If the Named Executive Officer's employment is terminated during the performance period for any reason other than death, total and permanent disability or retirement, then the award is canceled. The CSW Incentive Plan contains a provision accelerating awards upon a change in control of CSW. Except as provided in the next sentence, if a change in control of CSW occurs, all options become fully exercisable and all restrictions, terms and conditions applicable to all restricted stock are deemed lapsed and satisfied and all performance units are deemed to have been fully earned, as of the date of the change in control. Awards which have been outstanding for less than six months prior to the date the change in control occurs are not subject to acceleration upon the occurrence of a change in control. The CSW Incentive Plan also contains provisions designed to prevent circumvention of the above acceleration provisions through coerced termination of an employee prior to a change in control. See "Executive Compensation Committee Report" for a more thorough discussion of the terms of the CSW Incentive Plan.

Retirement Plan. CSW maintains the tax-qualified CSW Cash Balance Plan for eligible employees. In addition, CSW maintains the SERP, a non-qualified ERISA excess plan, that primarily provides benefits that cannot be payable under the CSW Cash Balance Plan because of maximum limitations imposed on such plans by the Code.

Through June 30, 1997, the CSW Cash Balance Plan was structured as a traditional, defined benefit final average pay plan. Effective July 1, 1997, the present value of accrued benefits under the Retirement Plan was converted to a cash balance.

Under the cash balance formula, each participant has an account, for recordkeeping purposes only, to which credits are allocated annually based on a percentage of the participant's pay. As of July 1, 1997, the definition of pay for the CSW Cash Balance Plan was expanded to include not only base pay but also bonuses, overtime, and commissions. The applicable percentage is determined by the age and years of vesting service the participant has with CSW and its affiliates as of December 31 of each year (or as of the participant's termination date, if earlier). The following table shows the applicable percentage used to determine credits at the age and years of service indicated:

Sum of Age plus Years of Service	Applicable Percentage
<30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

As of December 31, 1997, the sum of age plus years of service of the Named Executive Officers for the cash balance formula are as follows: Mr. Brooks, 96; Mr. Shockley, 73; Mr. Files, 76; Mr. Meyer, 74; and Mr. Rosilier, 71.

All balances in the accounts of participants earn a fixed rate of interest which is also credited annually. The interest rate for a particular year is the average rate of return of the 30-year Treasury Rate for November of the prior year. For 1997, the interest rate was 6.48%. For 1998, the interest rate is 6.11%. Interest continues to be credited as long as the participant's balance remains in the plan.

At retirement or other termination of employment, an amount equal to the vested balance (including qualified and SERP benefit) then credited to the account is payable to the participant in the form of an immediate or deferred lump-sum or annuity. Benefits (both from the CSW Cash Balance Plan and the SERP) under the cash balance formula are not subject to reduction for Social Security benefits or other offset amounts. The estimated annual benefit payable to each of the Named Executive Officers as a single life annuity at age 65 under the CSW Cash Balance Plan and the SERP is; Mr. Brooks, $464,599; Mr. Shockley, $230,384; Mr. Meyer, $144,432; Mr. Rosilier, $250,142; Mr. Files, $272,378. These projections are based on the following assumptions: (1) participant remains employed until age 65; (2) salary used is base pay paid for calendar year 1997 assuming no future increases plus bonus at 1997 target level; (3) interest credit at 6.11% for 1998 and future years; (4) the conversion of the lump-sum cash balance to a single life annuity at normal retirement age, based on an interest rate of 6.11% and the 1983 Group Annuity Mortality Table, which sets forth generally accepted life expectancies.

In addition, certain employees who were 50 or over and had completed at least 10 years of service as of July 1, 1997, also continue to earn a benefit using the prior pension formula. At commencement of benefits, the following Named Executive Officers have a choice of their accrued benefit using the cash balance formula or their accrued benefit using the prior pension formula: Mr. Brooks, Mr. Shockley, and Mr. Meyer. Once the participant selects either the earned benefit under the cash balance formula or the earned benefit under the prior pension formula, the other earned benefit is no longer available.

The table below shows the estimated combined benefits payable from both the prior pension formula and the SERP based on retirement age of 65, the average compensation shown, the years of credited service shown, continued existence of the prior pension formula without substantial change and payment in the form of a single life annuity.

Average Compensation	Annual Benefits After Specified Years of Credited Service 15	20	25	30 or more
$250,000	$ 62,625	$ 83,333	$104,167	$125,000
$350,000	$ 87,675	$116,667	$145,833	$175,000
$450,000	$112,725	$150,000	$187,500	$225,000
$550,000	$137,775	$183,333	$229,167	$275,000
$650,000	$162,825	$216,667	$270,833	$325,000
$750,000	$187,875	$250,000	$312,500	$375,000
$850,000	$212,500	$283,333	$357,000	$425,000

Benefits payable under the prior pension formula are based upon the participant's years of credited service, age at retirement, and covered compensation earned by the participant. The annual normal retirement benefit payable under the prior pension formula and the SERP are based on 1.67 percent of "Average Compensation" times the number of years of credited service (reduced by no more than 50 percent of a participant's age 62 or later Social Security benefit). "Average compensation" is covered compensation for the prior pension formula and equals the average annual compensation, reported as salary in the Summary Compensation Table, during the 36 consecutive months of highest pay during the 120 months prior to retirement.

Respective years of credited service and ages, as of December 31, 1997, for the three Named Executive Officers who continue to earn a benefit under the prior pension formula are: Mr. Brooks, 30 and 60; Mr. Shockley, 14 and 52; and Mr. Meyer, 16 and 58.

In addition, Mr. Shockley and Mr. Meyer have arrangements with CSW under which they will receive a total of 30 years of credited service using the prior pension formula (paid through the SERP) if they remain employed by CSW through age 60. In 1992, Mr. Meyer completed five consecutive years of employment which entitled him to receive five additional years of credited service (through the SERP) as included in his years of service for the cash balance formula and the prior pension formula as set forth above.

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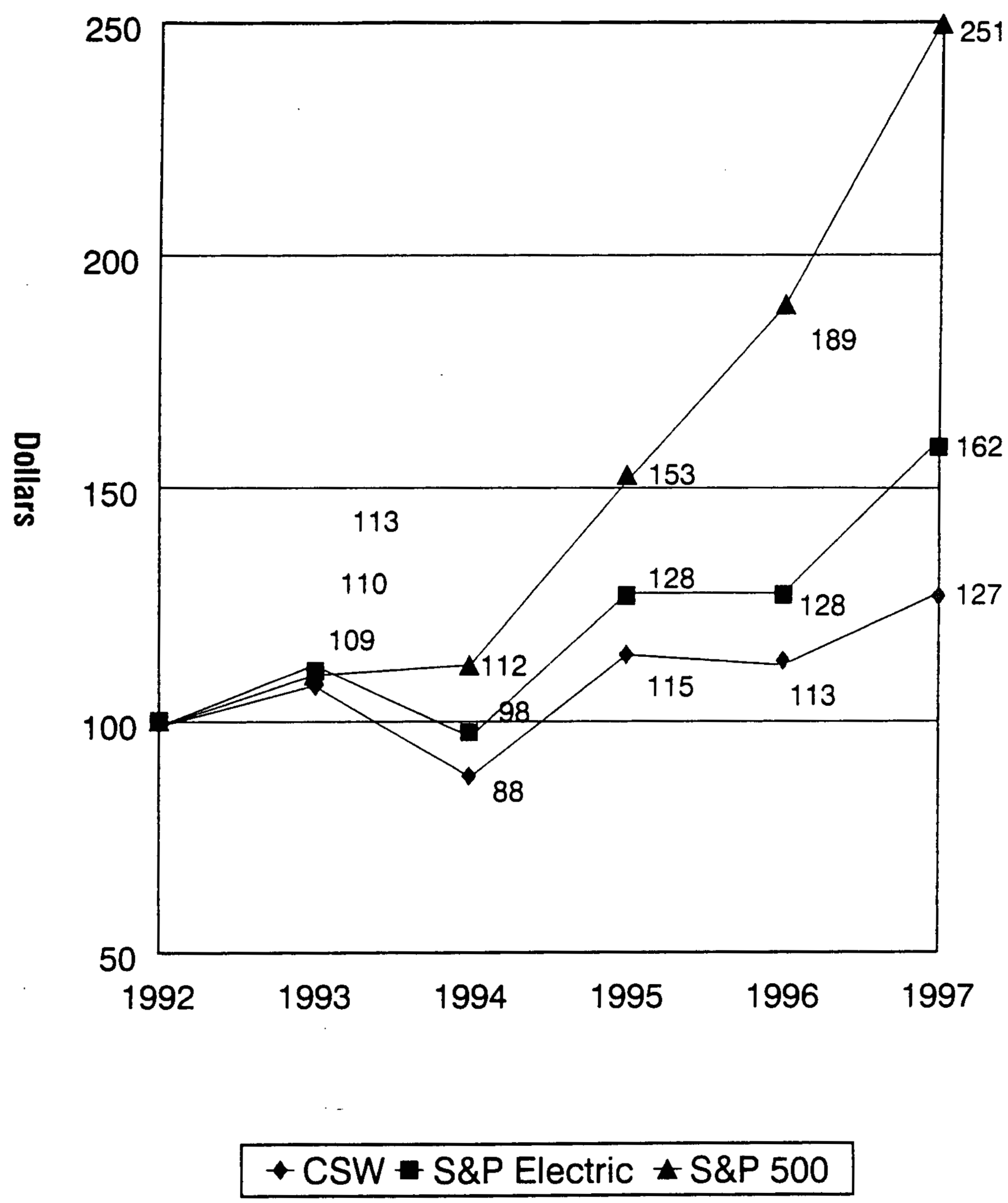
Comparison of Five Year Cumulative Total Return of Central and South West Corporation, the S&P 500 Index and the S&P Electric Cos. Index



The total return performance shown on the graph above is not necessarily indicative of future performance.

EXPERTS

The financial statements and related financial statement schedule incorporated in this Joint Proxy Statement/Prospectus by reference from AEP's Annual Report on Form 10-K have been audited by Deloitte & Touche LLP, independent auditors, as stated in their reports, which are incorporated herein by reference, and have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

The consolidated financial statements and schedules of CSW, incorporated by reference in this Joint Proxy Statement/Prospectus from CSW's Annual Report on Form 10-K have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report with respect thereto, and is incorporated by reference herein in reliance upon the authority of said firm as experts in accounting and auditing.

Representatives of Deloitte & Touche LLP are expected to be present at the AEP Meeting and representatives of Arthur Andersen LLP are expected to be present at the CSW Meeting, where they will have the opportunity to make a statement if they desire to do so and will be available to respond to appropriate questions.

LEGAL OPINIONS

The legality of the AEP Shares being offered hereby is being passed upon for AEP by Simpson Thacher & Bartlett, Counsel for AEP.

Simpson Thacher & Bartlett, counsel for AEP, and Christy & Viener, counsel for CSW, have delivered opinions concerning certain federal income tax consequences of the Merger. See "THE MERGER— Certain U.S. Federal Income Tax Consequences".

FUTURE SHAREHOLDER PROPOSALS

Any AEP shareholder proposals for the 1999 Annual Meeting of AEP Shareholders must be received by AEP, at 1 Riverside Plaza, Columbus, Ohio 43215, no later than November 10, 1998 for inclusion in the proxy statement and form of proxy for such meeting.

Any CSW stockholder proposals for the 1999 Annual Meeting of CSW Stockholders must be received by CSW, at 1616 Woodall Rogers Freeway, Dallas, Texas 75202, no later than November 1, 1998 for inclusion in the proxy statement and form of proxy for such meeting.

Internet web site described above. Documents incorporated by reference are available from your applicable company without charge, excluding all exhibits unless specifically incorporated by reference an exhibit in this Joint Proxy Statement/Prospectus. Shareholders may obtain documents incorporated by reference in this Joint Proxy Statement/Prospectus by requesting them in writing or by telephone from the appropriate company at the following addresses:

AMERICAN ELECTRIC POWER COMPANY, INC.
1 Riverside Plaza
Columbus, Ohio 43215
Attention: Shareholder Relations
Tel: 1-800-237-2667

CENTRAL AND SOUTH WEST CORPORATION
1616 Woodall Rodgers Freeway
Dallas, Texas 75202
Attention: Secretary
Tel: (214) 777-1000

If you would like to request documents, please do so by May 20, 1998 to receive them before the meetings. If you request any incorporated documents, the appropriate company will mail them to you by first-class mail, or other equally prompt means, within one business day of receipt of your request.

SEC rules require that an annual report of AEP, with respect to AEP shareholders, and of CSW, with respect to CSW stockholders, precede or accompany proxy material. More than one annual report need not be sent to the same address, if the recipient agrees. If more than one annual report was or is sent to your address, at your request, mailing of the duplicate copy to the account you select will be discontinued. You may so indicate in the space provided on your proxy card. Eliminating these duplicate mailings will not affect receipt of future proxy statements and proxy cards.

You should rely only on the information contained or incorporated by reference in this Joint Proxy Statement/Prospectus to vote your shares at the meetings. We have not authorized anyone to provide you with information that is different from what is contained in this Joint Proxy Statement/Prospectus. This Joint Proxy Statement/Prospectus is dated April 16, 1998. You should not assume that the information contained in the Joint Proxy Statement/Prospectus is accurate as of any date other than that date, and neither the mailing of this Joint Proxy Statement/Prospectus to shareholders nor the issuance of AEP Shares in the Merger shall create any implication to the contrary.

LIST OF DEFINED TERMS

† These terms are defined in the "Notice of Annual Meetings of Shareholders" page (beginning of document)

AGREEMENT AND PLAN OF MERGER

By and Among

American Electric Power Company, Inc.,

Augusta Acquisition Corporation

and

Central and South West Corporation

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AGREEMENT AND PLAN OF MERGER

THIS AGREEMENT AND PLAN OF MERGER, dated as of December 21, 1997, is by and among American Electric Power Company, Inc., a New York corporation ("AEP"), Augusta Acquisition Corporation, a Delaware corporation and a wholly owned subsidiary of AEP ("Newco"), and Central and South West Corporation, a Delaware corporation (the "Company"). AEP and Newco are sometimes collectively referred to herein as the "AEP Companies."

RECITALS:

The Board of Directors of the Company has determined that the business combination to be effected by means of the Merger is consistent with and in furtherance of the long-term business strategy of the Company and is fair to, and in the best interests of, the Company and its stockholders and has approved and adopted this Agreement and recommended approval and adoption of this Agreement by the stockholders of the Company.

The Board of Directors of AEP has determined that the business combination to be effected by means of the Merger is consistent with and in furtherance of the long-term business strategy of AEP and is fair to, and in the best interests of, AEP and its stockholders and has approved this Agreement, the Charter Amendment and the Share Issuance and recommended approval and adoption of the Charter Amendment and the Share Issuance by the stockholders of AEP.

The Board of Directors of Newco has determined that the business combination to be effected by means of the Merger is in the best interests of Newco and its stockholder and has approved and adopted this Agreement and recommended approval and adoption of this Agreement by AEP.

To give effect to the transactions contemplated hereby, upon the terms and subject to the conditions of this Agreement and in accordance with the Delaware Law, Newco will merge with and into the Company.

For Federal income tax purposes, it is intended that the Merger shall qualify as a reorganization under the provisions of Section 368(a) of the Code.

The Merger is intended to be treated as a "pooling of interests" for accounting purposes.

NOW, THEREFORE, in consideration of the foregoing and the respective representations, warranties, covenants and agreements set forth in this Agreement, the parties hereto agree as follows:

ARTICLE I

DEFINITIONS

SECTION 1.1 *Definitions.* Certain capitalized and other terms used in this Agreement are defined in Annex A hereto and are used herein with the meanings ascribed to them therein.

SECTION 1.2 *Rules of Construction.* Unless the context otherwise requires, as used in this Agreement: (a) a term has the meaning ascribed to it; (b) an accounting term not otherwise defined has the meaning ascribed to it in accordance with GAAP; (c) "or" is not exclusive; (d) "including" shall mean "including, without limitation;" (e) words in the singular include the plural; (f) words in the plural include the singular; (g) words applicable to one gender shall be construed to apply to each gender; (h) the terms "hereof," "herein," "hereby," "hereto" and derivative or similar words refer to this entire Agreement; and (i) the terms "Article" or "SECTION" shall refer to the specified Article or SECTION of this Agreement.

ARTICLE II

TERMS OF MERGER

SECTION 2.1 *Statutory Merger.* Subject to the terms and conditions and in reliance upon the representations, warranties, covenants and agreements contained herein, Newco shall merge (the "Merger") with and into the Company at the Effective Time. The terms and conditions of the Merger and the mode of carrying the same into effect shall be as set forth in this Agreement. As a result of the Merger, the separate corporate existence of Newco shall cease and the Company shall continue as the Surviving Corporation.

SECTION 2.2 *Effective Time.* As soon as practicable after the satisfaction or, if permissible, waiver of the conditions set forth in Article VIII, the parties hereto shall cause the Merger to be consummated by filing a Certificate of Merger (the "Certificate of Merger") with the Secretary of State of the State of Delaware, in such form as required by, and executed in accordance with the relevant provisions of, the Delaware Law.

SECTION 2.3 *Effect of the Merger.* At the Effective Time, the effect of the Merger shall be as provided in the applicable provisions of the Delaware Law. Without limiting the generality of the foregoing, and subject thereto, at the Effective Time, except as otherwise provided herein, all the property, rights, privileges, powers and franchises of Newco and the Company shall vest in the Surviving Corporation, and all debts, liabilities and duties of Newco and the Company shall become the debts, liabilities and duties of the Surviving Corporation.

SECTION 2.4 *Certificate of Incorporation; Bylaws.* At the Effective Time, the certificate of incorporation and the bylaws of the Company, as in effect immediately prior to the Effective Time, shall be the certificate of incorporation and the bylaws of the Surviving Corporation.

SECTION 2.5 *Directors and Officers.* The directors of Newco immediately prior to the Effective Time shall be the directors of the Surviving Corporation, each to hold office in accordance with the certificate of incorporation and bylaws of the Surviving Corporation, and the officers of the Company immediately prior to the Effective Time shall be the officers of the Surviving Corporation, in each case until their respective successors are duly elected or appointed and qualified.

ARTICLE III

CONVERSION OF SECURITIES; EXCHANGE OF CERTIFICATES

SECTION 3.1 *Merger Consideration; Conversion and Cancellation of Securities.* On the date on which the Effective Time occurs, by virtue of the Merger and without any action on the part of the AEP Companies, the Company or any securityholder thereof:

(a) Subject to the other provisions of this Article III, each share of Company Common Stock issued and outstanding immediately prior to the Effective Time (exclusive of any shares to be cancelled pursuant to SECTION 3.1(c)) shall be converted into that number of shares of AEP Common Stock equal to the Common Stock Exchange Ratio. If between the date of this Agreement and the Effective Time the outstanding shares of Company Common Stock or AEP Common Stock shall have been changed into a different number of shares or a different class, by reason of any dividend, subdivision, reclassification, recapitalization, split, combination, exchange of shares or other transaction, the Common Stock Exchange Ratio shall be correspondingly adjusted to reflect such dividend, subdivision, reclassification, recapitalization, split, combination, exchange of shares or other transaction.

(b) All shares of Company Common Stock shall, upon conversion into shares of AEP Common Stock at the Effective Time, cease to be outstanding and shall automatically be cancelled and retired, and each certificate previously evidencing shares of Company Common Stock outstanding immediately prior to the Effective Time (exclusive of any shares to be cancelled pursuant to SECTION 3.1(c)) shall thereafter be deemed, for all purposes other than the payment of dividends or distributions, to represent that number of shares of AEP Common Stock into which such shares of Company Common Stock were converted pursuant to SECTION 3.1(a) and, if applicable, the right to receive cash pursuant to SECTION 3.2(e). The holders of certificates previously evidencing Company Common Stock shall cease to have any rights with respect to such Company Common Stock except as otherwise provided herein or by law.

(c) Notwithstanding any provision of this Agreement to the contrary, each share of Company Common Stock held in the treasury of the Company and each share of Company Common Stock, if any, owned by AEP or any direct or indirect wholly owned subsidiary of AEP or of the Company immediately prior to the Effective Time shall be cancelled and extinguished without conversion thereof.

(d) Each share of common stock, par value $.01 per share, of Newco issued and outstanding immediately prior to the Effective Time shall be converted into one share of common stock, par value $3.50 per share, of the Surviving Corporation.

SECTION 3.2 *Exchange of Certificates.* (a) *Exchange Fund.* On or prior to the day of the Effective Time, AEP shall deposit, or cause to be deposited, with the Exchange Agent, for the benefit of the holders of Company Common Stock, for exchange in accordance with this Article III, through the Exchange Agent, certificates evidencing a number of shares of AEP Common Stock into which the number of shares of Company Common Stock issued and outstanding immediately prior to the Effective Time was converted pursuant to SECTION 3.1(a). The Exchange Agent shall, pursuant to irrevocable instructions from AEP, deliver AEP Common Stock, together with any cash to be paid in lieu of fractional interests in shares of AEP Common Stock pursuant to SECTION 3.2(e) and any dividends or distributions related thereto, in exchange for certificates theretofore evidencing Company Common Stock surrendered to the Exchange Agent pursuant to SECTION 3.2(c). Except as contemplated by SECTION 3.2(f), the Exchange Fund shall not be used for any other purpose.

(b) *Letter of Transmittal.* Promptly after the Effective Time, AEP will cause the Exchange Agent to send to each record holder of Company Common Stock immediately prior to the Effective Time a letter of transmittal and other appropriate materials for use in surrendering to the Exchange Agent certificates that prior to the Effective Time evidenced shares of Company Common Stock.

(c) *Exchange Procedures.* Promptly after the Effective Time, the Exchange Agent shall distribute to each former holder of Company Common Stock, upon surrender to the Exchange Agent for cancellation of one or more certificates that theretofore evidenced shares of Company Common Stock, certificates evidencing the appropriate number of shares of AEP Common Stock into which such shares of Company Common Stock were converted pursuant to the Merger, together with any cash to be paid in lieu of fractional interests in shares of AEP Common Stock pursuant to SECTION 3.2(e) and any dividends or distributions related thereto. If shares of AEP Common Stock are to be issued to a Person other than the Person in whose name the surrendered certificate or certificates are registered, it shall be a condition of issuance of AEP Common Stock that the surrendered certificate or certificates shall be properly endorsed, with signatures guaranteed, or otherwise in proper form for transfer and that the Person requesting such payment shall pay any transfer or other taxes required by reason of the issuance of AEP Common Stock to a Person other than the registered holder of the surrendered certificate or certificates or such Person shall establish to the satisfaction of AEP that such tax has been paid or is not applicable. Notwithstanding the foregoing, neither the Exchange Agent nor any party hereto shall be liable to any former holder of Company Common Stock for any AEP Common Stock, cash in lieu of fractional interests or dividends or distributions thereon delivered to a public official pursuant to any applicable escheat Law.

(d) *Distributions with Respect to Unexchanged Shares of Company Common Stock.* No dividends or other distributions declared or made with respect to AEP Common Stock with a record date after the Effective Time shall be paid to the holder of any certificate that theretofore evidenced shares of Company Common Stock until the holder of such certificate shall surrender such certificate. Subject to the effect of any applicable escheat Laws, following surrender of any such certificate, there shall be paid (i) to the holder of the certificates evidencing whole shares of AEP Common Stock issued in exchange therefor, without interest, (A) promptly, the amount of dividends or other distributions with a record date after the Effective Time theretofore paid with respect to such whole shares of AEP Common Stock, and (B) at the appropriate payment date, the amount of dividends or other distributions, with a record date after the Effective Time but prior to surrender and a payment date occurring after surrender, payable with respect to such whole shares of AEP Common Stock and (ii) to the holder of any certificate that theretofore evidenced shares of Company Common Stock, without interest, promptly the amount of any cash payable with respect to a fractional interest in a share of AEP Common Stock to which such holder is entitled pursuant to SECTION 3.2(e).

(e) *No Fractional Shares.* Notwithstanding anything herein to the contrary, no certificates or scrip evidencing fractional interests in shares of AEP Common Stock shall be issued in connection with the Merger, and any such fractional interests to which a holder of record of Company Common Stock at the Effective Time would otherwise be entitled will not entitle such holder to vote or to any rights of a stockholder of AEP. In lieu of any such fractional shares, each holder of record of Company Common Stock at the Effective Time who but for the provisions of this SECTION 3.2(e) would be entitled to receive a fractional interest of a share of AEP Common Stock pursuant to the Merger shall be paid cash, without any interest thereon, as hereinafter provided. AEP shall instruct the Exchange Agent to determine the number of whole shares and fractional shares of AEP Common Stock allocable to each holder of record of Company Common Stock at the Effective Time, to aggregate all such fractional shares into whole shares, to sell the whole shares obtained thereby in the open market at then prevailing prices on behalf of holders who otherwise would be entitled to receive fractional share interests and to distribute to each such holder such holder's ratable share of the total proceeds of such sale, after making appropriate deductions of the amount, if any, required for Federal income tax withholding purposes and after deducting any applicable transfer taxes. All brokers' fees and commissions and fees of the Exchange Agent incurred in connection with such sales shall be paid by AEP.

(f) *Termination of Exchange Fund.* Any portion of the Exchange Fund which remains unclaimed by the former holders of Company Common Stock for twelve months after the Effective Time shall be delivered to AEP, upon demand, and any former holders of Company Common Stock who have not theretofore complied with this Article III shall thereafter look only to AEP for AEP Common Stock, any cash to be paid in lieu of fractional interests in shares of AEP Common Stock and any dividends or other distributions to which they are entitled.

(g) *Withholding of Tax.* AEP shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement to any former holder of Company Common Stock such amounts as AEP (or any affiliate thereof) is required to deduct and withhold with respect to the making of such payment under the Code, or any provision of state, local or foreign tax Law. To the extent that amounts are so withheld by AEP, such withheld amounts shall be treated for all purposes of this Agreement as having been paid to the former holder of Company Common Stock in respect of which such deduction and withholding was made by AEP.

(h) *Lost Certificates.* If any certificate evidencing shares of Company Common Stock shall have been lost, stolen or destroyed, upon the making of an affidavit of that fact by the Person claiming such certificate to be lost, stolen or destroyed and, if required by AEP, the posting by such Person of a bond, in such reasonable amount as AEP may direct, as indemnity against claims that may be made against it with respect to such certificate, the Exchange Agent will issue in exchange for such lost, stolen or destroyed certificate a certificate evidencing that number of shares of AEP Common Stock into which the shares of Company Common Stock evidenced by such lost, stolen or destroyed certificate were converted pursuant to SECTION 3.1(a), any cash in lieu of fractional interests in shares of AEP Common Stock to which the holder thereof may be entitled pursuant to SECTION 3.2(e) and any dividends or other distributions to which the holder thereof may be entitled pursuant to SECTION 3.2(d).

SECTION 3.3 *Closing.* The Closing shall take place at such time and place as the parties shall mutually agree on the second Business Day immediately following the date on which the last of the conditions set forth in Article VIII (other than conditions that by their nature are required to be performed on the Closing Date) is fulfilled or, if permissible, waived, or at such other place, time and date as the parties hereto may agree. At the conclusion of the Closing on the Closing Date, the parties hereto shall cause the Certificate of Merger relating to the Merger to be filed with the Secretary of State of the State of Delaware.

SECTION 3.4 *Stock Transfer Books.* At the Effective Time, the stock transfer books of the Company shall be closed and there shall be no further registration of transfers of shares of Company Common Stock thereafter on the records of the Company.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF THE COMPANY

The Company hereby represents and warrants to the AEP Companies that:

SECTION 4.1 *Organization and Qualification; Subsidiaries.* The Company and each Subsidiary of the Company are legal entities duly organized, validly existing and in good standing under the Laws of their respective jurisdictions of incorporation or organization, have all requisite power and authority to own, lease and operate their respective properties and to carry on their respective businesses as they are now being conducted and are duly qualified and in good standing to do business in each jurisdiction in which the nature of the business conducted by them or the ownership or leasing of their respective properties makes such qualification necessary, other than any matters, including the failure to be so duly qualified and in good standing, that could not reasonably be expected to have a Material Adverse Effect on the Company. SECTION 4.1 of the Company's Disclosure Letter sets forth, as of the date of this Agreement, a true and complete list of all the Company's directly or indirectly owned Subsidiaries, together with (A) the jurisdiction of incorporation or formation of each Subsidiary and the percentage of each Subsidiary's outstanding capital stock or other equity interests owned by the Company or another Subsidiary of the Company, and (B) an indication of whether each such Subsidiary is a Significant Subsidiary. Except as set forth in SECTION 4.1 of the Company's Disclosure Letter, neither the Company nor any of its Subsidiaries owns an equity interest in any other partnership or joint venture arrangement or other business entity that is Material to the Company.

SECTION 4.2 *Certificate of Incorporation and Bylaws.* The Company has heretofore marked for identification and furnished to AEP complete and correct copies of the certificate of incorporation and the bylaws or the equivalent organizational documents, in each case as amended or restated to the date hereof. of the Company and each of its Significant Subsidiaries. Neither the Company nor any of its Significant Subsidiaries is in violation of any of the provisions of its certificate of incorporation or bylaws (or equivalent organizational documents).

SECTION 4.3 *Capitalization.* (a) *Company Common Stock.* The authorized capital stock of the Company consists of 350,000,000 shares of Company Common Stock of which as of November 7, 1997: (A) 212,235,320 shares were issued and outstanding, all of which are duly authorized, validly issued, fully paid and nonassessable and not subject to preemptive rights created by statute. the Company's certificate of incorporation or bylaws or any agreement to which the Company is a party or is bound and (B) 10,410,363 shares were reserved for future issuance in the amounts and for the purposes set forth in SECTION 4.3(a) of the Company's Disclosure Letter. Except as set forth in SECTION 4.3(a) of the Company's Disclosure Letter, between November 7, 1997 and the date of this Agreement, no shares of Company Common Stock have been issued by the Company and the Company has not granted any options for. or other rights to purchase, shares of Company Common Stock.

(b) *Reserved Shares.* Except for shares to which reference is made in SECTION 4.3(a), no shares of Company Common Stock are reserved for issuance, and, except for the Company's Rights Agreement and stock options shares with respect to which are reserved for issuance as set forth in SECTION 4.3(a) of the Company's Disclosure Letter, there are no contracts, agreements, commitments or arrangements obligating the Company to (i) offer, sell, issue or grant any Equity Securities of the Company, (ii) redeem, purchase or acquire, or offer to purchase or acquire, any outstanding Equity Securities of the Company or (iii) grant any Lien on any shares of capital stock of the Company.

(c) *Subsidiary Stock.* The authorized, issued and outstanding capital stock of, or other equity interests in, each of the Company's Significant Subsidiaries are set forth in SECTION 4.3(c) of the Company's Disclosure Letter. Except as set forth in SECTION 4.3(c) of the Company's Disclosure Letter, (i) all the issued and outstanding common stock of each of the Company's Significant Subsidiaries is owned, directly or indirectly, by the Company; (ii) all the issued and outstanding shares of each class of capital stock of, or other equity interests in, each of the Significant Subsidiaries of the Company have been duly authorized and are validly issued, and, with respect to capital stock, are fully paid and nonassessable, and were not issued in violation of any preemptive or similar rights of any past or present equity holder of such Significant Subsidiary; (iii) all such issued and outstanding shares, or other equity interests, that are indicated as owned by the Company or one of its Subsidiaries in SECTION 4.3(c) of the Company's Disclosure Letter are owned (A) beneficially as set forth therein and (B) free and clear of all Liens; (iv) no shares of capital stock of, or other equity interests in, any Significant Subsidiary of the Company are reserved for issuance; and (v) there are no contracts, agreements, commitments or arrangements obligating the Company or any of its Subsidiaries (A) to offer, sell, issue, grant, pledge, dispose of or encumber any Equity Securities of any of the Significant Subsidiaries of the Company, (B) to redeem, purchase or acquire, or offer to purchase or acquire, any outstanding Equity Securities of any of the Significant Subsidiaries of the Company or (C) to grant any Lien on any outstanding shares of capital stock of, or other equity interest in, any of the Significant Subsidiaries of the Company.

(d) *Adverse Claims.* Except for the Company's Rights Agreement and stock options shares with respect to which are reserved for issuance as set forth in SECTION 4.3(a) of the Company's Disclosure Letter, there are no voting trusts, proxies or other agreements, commitments or understandings of any character to which the Company or any of its Subsidiaries is a party or by which the Company or any of its Subsidiaries is bound with respect to the voting of any shares of capital stock of the Company or any of its Significant Subsidiaries, with respect to the registration of the offering, sale or delivery of any shares of capital stock of the Company or any of its Significant Subsidiaries under the Securities Act or otherwise relating to any shares of capital stock of the Company or any of its Significant Subsidiaries.

SECTION 4.4 *Authorization of Agreement.* The Company has all requisite corporate power and authority to execute and deliver this Agreement and each instrument required hereby to be executed and delivered by it at the Closing and, subject to obtaining the Required Company Vote, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby. The execution and delivery by the Company of this Agreement and each instrument required hereby to be executed and delivered by it at the Closing and the performance of its obligations hereunder and thereunder have been duly and validly authorized by all requisite corporate action on the part of the Company (other than, with respect to the Merger, the Required Company Vote). This Agreement has been duly executed and delivered by the Company and (assuming due authorization, execution and delivery hereof by the other parties hereto) constitutes a legal, valid and binding obligation of the Company, enforceable against the Company in accordance with its terms, except as the same may be limited by legal principles of general applicability governing the application and availability of equitable remedies.

SECTION 4.5 *Regulation and Approvals.* (a) *Utility Regulation.* The Company is a public utility holding company registered under, and subject to the provisions of, the Holding Company Act, and the Company is the parent, owning all the outstanding common stock, of four Domestic Public Utility Companies: (i) CP&L, which provides regulated retail electric service in the State of Texas; (ii) PSO, which provides regulated retail electric service in the State of Oklahoma; (iii) SWEPCO, which provides regulated retail electric service in the States of Texas, Louisiana and Arkansas; and (iv) WTU, which provides regulated retail electric service in the State of Texas. In addition, the Company indirectly owns all of the outstanding stock of Seeboard, a regulated regional electricity company in England and Wales. Seeboard is a Foreign Utility Company. Except as aforesaid and as set forth in SECTION 4.5(a) of the Company's Disclosure Letter, neither the Company nor any of its Subsidiaries is subject to rate regulation as a public utility or public service company (or similar designation) by any state in the United States or any municipality or other political subdivision of any state, by the United States or any Governmental Authority of the United States or by any foreign country.

(b) *Approvals.* Except for the applicable requirements set forth in SECTION 4.5(b) of the Company's Disclosure Letter, no declaration, filing or registration with, no waiting period imposed by and no Permit or Order of, any Governmental Authority is required under any Law, Regulation or Order applicable to the Company or any of its Subsidiaries to permit the Company to execute, deliver or perform this Agreement or any instrument required hereby to be executed and delivered by it at the Closing, the failure to obtain which could reasonably be expected to have a Material Adverse Effect on the Company.

SECTION 4.6 *No Violation.* Assuming receipt of all Permits and Orders indicated as required in SECTION 4.5(b) and receipt of the Required Company Vote, neither the execution and delivery by the Company of this Agreement or any instrument required hereby to be executed and delivered by it at the Closing nor the performance by the Company of its obligations hereunder or thereunder will (a) violate or breach the terms of or cause a default under, or result in the termination of, or accelerate the performance required by, or result in a right of termination, cancellation or acceleration of any obligation under, or result in the creation of any lien, security interest, charge or encumbrance upon, any of the properties or assets of the Company or any of its Subsidiaries under (i) any Law, Regulation, Permit or Order applicable to the Company or any of its Subsidiaries, (ii) the certificate of incorporation or bylaws or similar organizational documents of the Company or any of its Subsidiaries or (iii) except as set forth in SECTION 4.6 of the Company's Disclosure Letter, any note, bond, mortgage, indenture, deed of trust, license, franchise, concession, lease, contract or agreement to which the Company or any of its Subsidiaries is a party or by which it or any of its properties or assets is bound, or (c) with the passage of time, the giving of notice or the taking of any action by a third Person, have any of the effects set forth in clause (a) of this SECTION, except in any such case for any matters described in clauses (i) and (iii) of this SECTION that could not reasonably be expected to have a material adverse effect upon the ability of the Company to perform its obligations under this Agreement or a Material Adverse Effect on the Company. Prior to the execution of this Agreement, the Board of Directors of the Company has taken all necessary action to cause this Agreement and the transactions contemplated hereby to be exempt from the provisions of SECTION 203 of the Delaware Law and to ensure that the execution, delivery and performance of this Agreement by the parties hereto will not cause any rights to be distributed or to become exercisable under the Company's Rights Agreement.

SECTION 4.7 *Reports.* (a) *Reports.* Since January 1, 1993, the Company and its Subsidiaries have filed or caused to be filed (i) all SEC Reports of the Company or any of its Subsidiaries required to be filed with the Commission and (ii) all other Reports of the Company or any of its Subsidiaries required to be filed with any Governmental Authorities, including the FERC, the Commission (under the Holding Company Act), the NRC and State Regulatory Commissions, except where the failure to file any such Reports of the Company or any of its Subsidiaries could not reasonably be expected to have a Material Adverse Effect on the Company. The Company has made available to AEP a true and complete copy of each such SEC Report. The Reports of the Company and its Subsidiaries, including all those filed after the date of this Agreement and prior to the Effective Time, (i) were or will be prepared in all material respects in accordance with the requirements of applicable Law and (ii), in the case of the SEC Reports of the Company and its Subsidiaries, did not at the time they were filed, or will not at the time they are filed, contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

(b) *Financial Statements.* The Company's Consolidated Financial Statements and any condensed financial statements of the Company (including any related notes thereto) contained in any SEC Reports of the Company or any of its Subsidiaries filed with the Commission after the date of this Agreement (i) have been or will have been prepared in accordance with the published Regulations of the Commission and in accordance with GAAP (except (A) to the extent required by changes in GAAP, (B) with respect to unaudited financial statements as permitted by Form 10-Q and (C), with respect to SEC Reports of the Company or any of its Subsidiaries filed prior to the date of this Agreement, as may be indicated in the notes thereto) and (ii) fairly present the consolidated financial position of the Company and its Subsidiaries as of the respective dates thereof and the consolidated results of their operations and cash flows for the periods indicated (including, in the case of any unaudited interim financial statements, reasonable estimates of normal and recurring year-end adjustments).

(c) *No Omissions.* Except for matters disclosed in SECTION 4.7(c) of the Company's Disclosure Letter, or matters disclosed in the Company's SEC Reports filed with the Commission prior to the date hereof, there exist no liabilities or obligations of the Company and its Subsidiaries, whether accrued, absolute, contingent or threatened, that would be required to be reflected, reserved for or disclosed under GAAP in condensed financial statements of the Company as of and for the period ended on the dates on which this representation and warranty is made or deemed to be made, other than (i) liabilities or obligations that are adequately reflected, reserved for or disclosed in the Company's Consolidated Financial Statements, (ii) liabilities or obligations incurred in the ordinary course of business of the Company consistent with past practice since September 30, 1997, (iii) liabilities or obligations the incurrence of which would not have been prohibited by SECTIONs 6.1 or 6.2(a) had such sections been in effect since September 30, 1997 and (iv) other liabilities and obligations that could not reasonably be expected to have a Material Adverse Effect on the Company.

SECTION 4.8 *No Material Adverse Effect; Conduct.* (a) *Material Adverse Changes.* Except as set forth in SECTION 4.8(a) of the Company's Disclosure Letter, since September 30, 1997, no event (other than any event that is of general application to the electric utility industry in the United States or the United Kingdom) has occurred that, individually or together with other similar events, has had, and, to the Knowledge of the Company, no fact or condition (other than any fact or condition that is of general application to the electric utility industry in the United States or the United Kingdom) exists that could reasonably be expected to have, a Material Adverse Effect on the Company.

(b) *Proscribed Conduct.* Except as set forth in SECTION 4.8(b) of the Company's Disclosure Letter, during the period from September 30, 1997 to the date of this Agreement, neither the Company nor any of its Subsidiaries has failed to conduct its business in the ordinary course consistent with past practice, other than any conduct that would not have been prohibited by SECTION 6.1 or SECTION 6.2(a) had such sections been in effect since September 30, 1997.

SECTION 4.9 *Permits; Compliance.* (a) *General.* The Company and its Subsidiaries have obtained all Orders and Permits that are necessary to carry on their businesses as currently conducted, except for any such Orders or Permits that the failure to possess, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on the Company. Except as set forth in SECTION 4.14 of the Company's Disclosure Letter, all such Orders and Permits are in full force and effect, have not been violated in any respect that could reasonably be expected to have a Material Adverse Effect on the Company and no suspension, revocation or cancellation thereof has occurred or, to the Knowledge of the Company, been threatened and there is no action, proceeding or investigation pending or, to the Knowledge of the Company, threatened regarding suspension, revocation or cancellation of any of such Permits or Orders, except where the suspension, revocation or cancellation of such Permits or Orders could not reasonably be expected to have a Material Adverse Effect on the Company.

(b) *South Texas Nuclear Facility.* CP&L is a co-owner of the South Texas Nuclear Facility, owning an undivided 25.2% interest therein. The operations of the South Texas Nuclear Facility are subject to the control of the STP Nuclear Operating Company (the "Operating Company"), in which the Company owns a like equity interest. Except as set forth in SECTION 4.9(b) of the Company's Disclosure Letter, to the Knowledge of the Company, the operations of the South Texas Nuclear Facility have at all times been conducted in compliance with applicable health, safety, regulatory and other legal requirements, except where the failure to be so in compliance in the aggregate could not reasonably be expected to have a Material Adverse Effect on the Company. Except as set forth in SECTION 4.9(b) of the Company's Disclosure Letter, to the Knowledge of the Company the operations of the South Texas Nuclear Facility are not the subject of any outstanding notices of violation or requests for information from the NRC or any other agency with jurisdiction over such facility. To the Knowledge of the Company, the Operating Company maintains, and is in compliance with, an emergency plan designed to protect the health and safety of the public in the event of an unplanned release of radioactive materials from the South Texas Nuclear Facility, and the NRC has determined that such plan is in compliance with its requirements. To the Knowledge of the Company, liability insurance to the full extent required by Law for operating nuclear facilities remains in full force and effect with respect to the South Texas Nuclear Facility, and the amount of such insurance has been approved by the NRC. To the Knowledge of the Company, plans for the decommissioning of the South Texas Nuclear Facility, and for the storage of spent nuclear fuel, conform with the requirements of applicable Law, and the owners of such facility, including the Company, have funded such plans to the extent required by Law.

SECTION 4.10 *Litigation; Compliance with Laws.* There are no actions, suits, investigations or proceedings (including any proceedings in arbitration) pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries, at law or in equity, in any Court or before or by any Governmental Authority, except actions, suits or proceedings that (a) are fully and accurately disclosed in the Company's SEC Reports filed with the Commission prior to the date hereof, (b) are set forth in SECTION 4.10 or SECTION 4.14 of the Company's Disclosure Letter or (c), individually or, with respect to multiple actions, suits or proceedings that allege similar theories of recovery based on similar facts, in the aggregate, could not reasonably be expected to have a Material Adverse Effect on the Company. Except as set forth in SECTION 4.10 of the Company's Disclosure Letter, there are no Material claims pending or, to the Knowledge of the Company, threatened by any Persons against the Company or any of its Subsidiaries for indemnification pursuant to any statute, organizational document, contract or otherwise with respect to any action, suit, investigation or proceeding pending in any Court or before or by any Governmental Authority. Except as set forth in SECTION 4.10 or SECTION 4.14 of the Company's

Disclosure Letter, the Company and its Subsidiaries are in substantial compliance with all applicable Laws and Regulations and are not in default with respect to any Order applicable to the Company or any of its Subsidiaries, except such events of noncompliance or defaults that, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on the Company.

SECTION 4.11 *Ownership of AEP Common Stock.* Neither the Company nor any of its Affiliates "beneficially own" (as such term is defined for purposes of SECTION 13(d) of the Exchange Act) any shares of AEP Common Stock (in whole or in part).

SECTION 4.12 *Employee Benefit Plans.* (a) *Listing.* Each Company Benefit Plan is listed in SECTION 4.12(a) of the Company's Disclosure Letter, including, with respect to Terminated Company Benefit Plans, the date of termination. True and correct copies of each of the following have been made available to AEP with respect to each Current Company Benefit Plan: (i) the three most recent annual reports (Form 5500) filed with the IRS, (ii) the plan document, (iii) the trust agreement, if any, (iv) the most recent summary plan description if required by ERISA, (v) the three most recent actuarial reports or valuations relating to each Current Company Benefit Plan subject to Title IV of ERISA and (vi) the most recent determination letter, if any, issued by the IRS with respect to any Current Company Benefit Plan intended to be qualified under SECTION 401 of the Code.

(b) *Material Adverse Changes.* With respect to each Company Benefit Plan, no event has occurred and, to the Knowledge of the Company, there exists no condition or set of circumstances in connection with which the Company or any of its Subsidiaries could be subject to any liability under the terms of such Company Benefit Plan, ERISA, the Code or any other applicable Law, other than any condition or set of circumstances that could not reasonably be expected to have a Material Adverse Effect on the Company.

(c) *Qualified Status of Current Plans.* Except as set forth in SECTION 4.12(c) of the Company's Disclosure Letter, each Current Company Benefit Plan intended to be qualified under SECTION 401 of the Code (i) satisfies in form the requirements of such SECTION, (ii) has received a favorable determination letter from the IRS regarding such qualified status, (iii) has not, since receipt of the most recent favorable determination letter, been amended, and, (iv) to the Knowledge of the Company, has not been operated in a way that would adversely affect its qualified status.

(d) *No Terminations of Current Plans.* There has been no termination or partial termination of any Current Company Benefit Plan within the meaning of SECTION 411(d)(3) of the Code.

(e) *Terminated Plans.* Any Terminated Company Benefit Plan intended to have been qualified under SECTION 401 of the Code received a favorable determination letter from the IRS with respect to its termination.

(f) *Claims.* There are no actions, suits or claims pending (other than routine claims for benefits) or, to the Knowledge of the Company, threatened against, or with respect to, any Company Benefit Plan or its assets that could reasonably be expected to have a Material Adverse Effect on the Company and, to the Knowledge of the Company, no facts or circumstances exist that could give rise to any such actions, suits or claims.

(g) *Pending Matters.* To the Knowledge of the Company, there is no matter pending (other than routine qualification determination filings) with respect to any Company Benefit Plan before the IRS, the Department of Labor, the PBGC or other Governmental Authority.

(h) *Timely Contributions.* Except as set forth in SECTION 4.12(h) of the Company's Disclosure Letter, all contributions required to be made to Company Benefit Plans pursuant to their terms and the provisions of ERISA, the Code or any other applicable Law have been timely made.

(i) *Current Plans Subject to Title IV of ERISA.* As to each Current Company Benefit Plan subject to Title IV of ERISA, (i) there has been no event or condition that presents a significant risk of plan termination, (ii) no accumulated funding deficiency, whether or not waived, within the meaning of

SECTION 302 of ERISA or SECTION 412 of the Code has been incurred, (iii) no reportable event within the meaning of SECTION 4043 of ERISA (for which the disclosure requirements of Regulation section 4043.1 et seq. promulgated by the PBGC have not been waived) has occurred within six years prior to the date of this Agreement, (iv) no notice of intent to terminate such Benefit Plan has been given under SECTION 4041 of ERISA, (v) no proceeding has been instituted under SECTION 4042 of ERISA to terminate such Benefit Plan, (vi) no liability to the PBGC has been incurred (other than with respect to required premium payments) and (vii) the assets of such Benefit Plan equal or exceed the actuarial present value of the benefit liabilities, within the meaning of SECTION 4041 of ERISA, under such Benefit Plan, based upon reasonable actuarial assumptions and the asset valuation principles established by the PBGC.

(j) *Excess Parachute Payments.* Except as set forth in SECTION 4.12(j) of the Company's Disclosure Letter and except for any Retention Agreement not prohibited by SECTION 6.2(a), in connection with the consummation of the transactions contemplated by this Agreement, no payments of money or other property, acceleration of benefits or provision of other rights have been or will be made under any Current Company Benefit Plan that could reasonably be expected to be nondeductible under SECTION 280G of the Code, whether or not some other subsequent action or event would be required to cause such payment, acceleration or provision to be triggered.

(k) *No Required Increase in Contributions.* Except as set forth in SECTION 4.12(k) of the Company's Disclosure Letter, the execution and delivery of this Agreement and the consummation of the transactions contemplated hereby will not (i) require the Company or any of its Subsidiaries to make a larger contribution to, or pay greater benefits or provide other rights under, any Current Company Benefit Plan than it otherwise would, whether or not some other subsequent action or event would be required to cause such payment or provision to be triggered or (ii) create or give rise to any additional vested rights or service credits under any Current Company Benefit Plan whether or not some other subsequent action or event would be required to cause such creation or acceleration to be triggered.

(l) *Intentionally Omitted.*

(m) *Retiree Benefits.* Except as set forth in SECTION 4.12(m) of the Company's Disclosure Letter, no Current Company Benefit Plan (other than a Company Benefit Plan maintained outside the United States that is either fully insured or fully funded through a retirement plan) provides retiree medical or retiree life insurance benefits to any Person and neither the Company nor any of its Subsidiaries is contractually or otherwise obligated (whether or not in writing) to provide any Person with life insurance or medical benefits upon retirement or termination of employment, other than as required by the provisions of SECTIONs 601 through 608 of ERISA and SECTION 4980B of the Code.

(n) *Multiemployer Plans.* Except as set forth in SECTION 5.1 of AEP's Disclosure Letter, neither the Company nor any member of its Controlled Group contributes or has an obligation to contribute, and has not within six years prior to the date of this Agreement contributed, had an obligation to contribute, or had any other liability to a multiemployer plan within the meaning of SECTION 3(37) of ERISA.

(o) *Collective Bargaining Contracts.* Except as set forth in SECTION 4.12(o) of the Company's Disclosure Schedule, (i) no collective bargaining agreement is being negotiated by the Company or any of its Subsidiaries, (ii) there is no pending or, to the Knowledge of the Company, threatened labor dispute, strike or work stoppage against the Company or any of its Subsidiaries that could reasonably be expected to have a Material Adverse Effect on the Company, (iii) to the Knowledge of the Company, neither the Company or any of its Subsidiaries nor any representative or employee of the Company or any of its Subsidiaries has in the United States committed any Material unfair labor practices in connection with the operation of the business of the Company and its Subsidiaries, and (iv) there is no pending or, to the Knowledge of the Company, threatened charge or complaint against the Company or any of its Subsidiaries by the National Labor Relations Board or any comparable agency of any state of the United States.

(p) *Funding of Certain Benefits.* Except as set forth in SECTION 4.12(p) of the Company's Disclosure Letter, the Company has not contributed, transferred or otherwise provided any cash, securities or other property to any grantee, trust, escrow or other arrangement that has the effect of providing or setting aside assets for benefits payable pursuant to any termination, severance or other change in control agreement.

SECTION 4.13 *Taxes.* (a) *Tax Returns and Taxes.* Except for such matters as could not reasonably be expected to have a Material Adverse Effect on the Company, (i) all Tax Returns that are required to be filed by or with respect to the Company or any of its Subsidiaries on or before the Effective Time have been or will be timely filed, (ii) all Taxes that are due and payable by the Company or any of its Subsidiaries on or before the Effective Time have been or will be timely paid in full or adequate reserves have been established for the payment of such Taxes, (iii) all withholding Tax requirements imposed on or with respect to the Company or any of its Subsidiaries and that are required to be satisfied at or before the Effective Time have been or will be satisfied in full in all respects and (iv) no penalty, interest or other charge is or will become due with respect to the late filing of any such Tax Return or late payment of any Tax by the Company or any of its Subsidiaries.

(b) *Audits.* Except as set forth in SECTION 4.13(b) of the Company's Disclosure Letter, all Material Tax Returns required to be filed by the Company or any of its Subsidiaries have been audited (and such audit has become final) by the applicable Governmental Authority or the applicable statute of limitations has expired for the period covered by such Tax Returns.

(c) *Extensions of Time.* Except as set forth in SECTION 4.13(c) of the Company's Disclosure Letter, there is not in force any extension of time with respect to the due date for the filing of any Material Tax Return required to be filed by the Company or any of its Subsidiaries or any waiver or agreement for any extension of time for the assessment or payment of any Tax due with respect to the period covered by any Tax Return filed, or required to be filed, by the Company or any of its Subsidiaries.

(d) *Claims.* No Material issues have been raised by any Taxing authority in connection with the audit or examination of any Tax Return filed, or required to be filed, by the Company or any of its Subsidiaries, and there is no claim against the Company or any of its Subsidiaries for any Taxes, and no assessment, deficiency or adjustment has been asserted or proposed with respect to any Tax Return, that, in either case, could reasonably be expected to have a Material Adverse Effect on the Company.

(e) *Affiliated Group.* Except as set forth in SECTION 4.13(e) of the Company's Disclosure Letter, none of the Company and its Subsidiaries, during the last ten years, has been a member of an affiliated group filing a consolidated Federal income Tax Return other than an affiliated group of which the Company is the common parent.

SECTION 4.14 *Environmental Matters.* Except for matters disclosed in SECTION 4.14 of the Company's Disclosure Letter, or matters disclosed in the Company's SEC Reports filed with the Commission prior to the date hereof, and except for matters that, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on the Company, (a) the properties, operations and activities of the Company and its Subsidiaries are in compliance with all applicable Environmental Laws; (b) the Company and its Subsidiaries and the properties and operations of the Company and its Subsidiaries are not subject to any existing, pending or, to the Knowledge of the Company, threatened action, suit, investigation, inquiry or proceeding by or before any Court or Governmental Authority under any Environmental Law; (c) all Permits, if any, required to be obtained or filed by the Company or any of its Subsidiaries under any Environmental Law in connection with the business of the Company and its Subsidiaries have been obtained or filed and are valid and currently in full force and effect; (d) to the Knowledge of the Company, there has been no release of any hazardous substance, pollutant or contaminant into the environment by the Company or its Subsidiaries or in connection with their properties or operations; (e) to the Knowledge of the Company, there has been no exposure of any Person or property to any hazardous substance, pollutant or contaminant in connection with the properties, operations and activities of the Company and its Subsidiaries; and (f) the Company and its Subsidiaries have made available to AEP all internal and external environmental audits and studies and all correspondence on substantial environmental matters (in each case relevant to the Company or any of its Subsidiaries) in the possession of the Company or its Subsidiaries.

SECTION 4.15 *Insurance.* The Company and its Subsidiaries own and are, and have been continuously since January 1, 1993, beneficiaries under all such insurance policies underwritten by reputable insurers that, as to risks insured, coverages and related limits and deductibles, are customary in the industries in which the Company and its Subsidiaries operate. Except as disclosed in SECTION 4.15 of the Company's Disclosure Letter, neither the Company nor any of it Subsidiaries has received any notice of cancellation or termination of any Material insurance policy as to which it is a named beneficiary. All Material insurance policies of the Company and its Subsidiaries are valid and enforceable against the underwriters thereof in accordance with their terms, except as the same may be limited by legal principles of general applicability governing the application and availability of equitable remedies.

SECTION 4.16 *Pooling; Tax Matters.* Neither the Company nor, to the Knowledge of the Company, any of its Affiliates has taken or agreed to take any action that would prevent the Merger from being treated as a "pooling of interests" in accordance with generally accepted accounting principles and the Regulations of the Commission or from constituting a reorganization within the meaning of section 368(a) of the Code.

SECTION 4.17 *Affiliates.* SECTION 4.17 of the Company's Disclosure Letter contains a true and complete list of all Persons who, to the Knowledge of the Company, may be deemed to be "affiliates" of the Company as such term is used in Rule 145 under the Securities Act, including all directors and executive officers of the Company.

SECTION 4.18 *Opinion of Financial Advisor.* The Company has received the opinion of Morgan Stanley & Co. Incorporated on the date of this Agreement to the effect that the consideration to be received by the holders of Company Common Stock in the Merger is fair, from a financial point of view, to such holders.

SECTION 4.19 *Brokers.* Except as set forth in SECTION 4.19 of the Company's Disclosure Letter, no broker, finder or investment banker (other than Morgan Stanley & Co. Incorporated) is entitled to any brokerage, finder's or other fee or commission in connection with the transactions contemplated by this Agreement based upon arrangements made by or on behalf of the Company. Prior to the date of this Agreement, the Company has made available to AEP complete and correct copies of all agreements between the Company and Morgan Stanley & Co. Incorporated pursuant to which such firm will be entitled to any payment relating to the transactions contemplated by this Agreement.

SECTION 4.20 *Vote Required.* The approval by the holders of a majority of the votes entitled to be cast by holders of the Company Common Stock, with each share of Company Common Stock being entitled to one vote per share, is the only vote of the holders of any class or series of capital stock of the Company or any of its Subsidiaries required to approve the Merger, this Agreement or the transactions contemplated hereby (the "Required Company Vote").

ARTICLE V

REPRESENTATIONS AND WARRANTIES OF THE AEP COMPANIES

The AEP Companies hereby represent and warrant to the Company that:

SECTION 5.1 *Organization and Qualification; Subsidiaries.* AEP and each Subsidiary of AEP are legal entities duly organized, validly existing and in good standing under the Laws of their respective jurisdictions of incorporation or organization, have all requisite power and authority to own, lease and operate their respective properties and to carry on their respective businesses as they are now being conducted and are duly qualified and in good standing to do business in each jurisdiction in which the nature of the business conducted by them or the ownership or leasing of their respective properties makes such qualification necessary, other than any matters, including the failure to be so duly qualified and in good standing, that could not reasonably be expected to have a Material Adverse Effect on AEP. SECTION 5.1 of AEP's Disclosure Letter sets forth, as of the date of this Agreement, a true and complete list of all of the directly or indirectly owned Subsidiaries of AEP, together with (A) the jurisdiction of incorporation of each Subsidiary and the percentage of each Subsidiary's outstanding voting securities owned by AEP or another Subsidiary of AEP, and (B) an indication of whether each such Subsidiary is a Significant Subsidiary. Except as set forth in SECTION 5.1 of AEP's Disclosure Letter, neither AEP nor any of its Subsidiaries owns an equity interest in any other partnership or joint venture arrangement or other business entity that is Material to AEP.

SECTION 5.2 *Certificate of Incorporation and Bylaws.* AEP has heretofore marked for identification and furnished to the Company complete and correct copies of the certificate of incorporation and the bylaws or the equivalent organizational documents, in each case as amended or restated to the date hereof, of AEP, Newco and each of AEP's Significant Subsidiaries. Neither AEP, Newco, nor any of AEP's Significant Subsidiaries is in violation of any of the provisions of its certificate of incorporation or bylaws (or equivalent organizational documents).

SECTION 5.3 *Capitalization.* (a) *AEP Common Stock.* The authorized capital stock of AEP consists of 300,000,000 shares of AEP Common Stock of which as of the date hereof: (A) 189,989,989 shares were issued and outstanding, all of which are duly authorized, validly issued, fully paid and nonassessable and not subject to preemptive rights created by statute, AEP's certificate of incorporation or bylaws or any agreement to which AEP is a party or is bound and (B) 51,581,493 shares were reserved for future issuance in the amounts and for the purposes set forth in SECTION 5.3(a) of AEP's Disclosure Letter.

(b) *Reserved Shares.* Except for shares to which reference is made in SECTION 5.3(a), no shares of AEP Common Stock are reserved for issuance, and there are no contracts, agreements, commitments or arrangements obligating AEP to (i) offer, sell, issue or grant any Equity Securities of AEP, (ii) to redeem, purchase or acquire, or offer to purchase or acquire, any outstanding Equity Securities of AEP or (iii) grant any Lien on any shares of capital stock of AEP.

(c) *Subsidiary Stock.* The authorized, issued and outstanding capital stock of, or other equity interests in, each of AEP's Significant Subsidiaries and Newco are set forth in SECTION 5.3(c) of AEP's Disclosure Letter. Except as set forth in SECTION 5.3(c) of AEP's Disclosure Letter, (i) all the issued and outstanding common stock of each of AEP's Significant Subsidiaries and Newco is owned, directly or indirectly, by AEP; (ii) all the issued and outstanding shares of each class of capital stock of, or other equity interests in, each of the Significant Subsidiaries of AEP and Newco have been duly authorized and are validly issued, and, with respect to capital stock, are fully paid and nonassessable, and were not issued in violation of any preemptive or similar rights of any past or present equity holder of such Significant Subsidiary; (iii) all such issued and outstanding shares, or other equity interests, that are indicated as owned by AEP, Newco or one of its Subsidiaries in SECTION 5.3(c) of AEP's Disclosure Letter are owned (A) beneficially as set forth therein and (B) free and clear of all Liens; (iv) no shares of capital stock of, or other equity interests in, any Significant Subsidiary of AEP or Newco are reserved for issuance; and (v) there are no contracts, agreements, commitments or arrangements obligating AEP or any of its Significant Subsidiaries or Newco (A) to offer, sell, issue, grant, pledge, dispose of or encumber any Equity Securities of any of the Significant Subsidiaries of AEP or Newco or (B) to redeem, purchase or acquire, or offer to purchase or acquire, any outstanding Equity Securities of any of the Significant Subsidiaries of AEP or Newco or (C) to grant any Lien on any outstanding shares of capital stock of, or other equity interest in, any of the Significant Subsidiaries of AEP or Newco.

(d) *Adverse Claims.* There are no voting trusts, proxies or other agreements, commitments or understandings of any character to which AEP or any of its Subsidiaries is a party or by which AEP or any of its Subsidiaries is bound with respect to the voting of any shares of capital stock of AEP, any of its Significant Subsidiaries or Newco, with respect to the registration of the offering, sale or delivery of any shares of capital stock of AEP or any of its Significant Subsidiaries or Newco under the Securities Act or otherwise relating to any shares of capital stock of AEP, any of its Significant Subsidiaries or Newco.

SECTION 5.4 *Authorization of Agreement.* Each of AEP and Newco has all requisite corporate power and authority to execute and deliver this Agreement and each instrument required hereby to be executed and delivered by it at the Closing and, subject to obtaining the Required AEP Vote, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby. The execution and delivery by each of AEP and Newco of this Agreement and each instrument required hereby to be executed and delivered by it at the Closing and the performance of their respective obligations hereunder and thereunder have been duly and validly authorized by all requisite corporate action on the part of AEP and Newco (other than the Required AEP Vote). This Agreement has been duly executed and delivered by AEP and Newco and (assuming due authorization, execution and delivery hereof by the Company) constitutes a legal, valid and binding obligation of each of AEP and Newco, enforceable against each of them in accordance with its terms, except as the same may be limited by legal principles of general applicability governing the application and availability of equitable remedies.

SECTION 5.5 *Regulation and Approvals.* (a) *Utility Regulation.* AEP is a public utility holding company registered under, and subject to the provisions of, the Holding Company Act, and AEP is the parent, owning all the outstanding common stock, of seven Domestic Public Utility Companies: (i) APCo, which provides regulated retail electricity service in the States of Virginia and West Virginia and which is also regulated in the State of Tennessee; (ii) CSPCo, which provides regulated retail electricity service in the State of Ohio; (iii) I&M, which provides regulated retail electricity service in the States of Indiana and Michigan; (iv) KEPCo, which provides regulated retail electricity service in the State of Kentucky; (v) KPC, which provides regulated retail electricity service in the State of Tennessee; (vi) OPCo, which provides regulated retail electricity service in the State of Ohio and which is also regulated in the State of West Virginia and (vii) WPC, which provides regulated retail electricity service in the State of West Virginia. In addition, AEP indirectly owns 50% of Yorkshire Electricity Group plc, a regulated regional electricity company in the United Kingdom ("Yorkshire"). Yorkshire is a Foreign Utility Company. Except for regulation of the aforesaid companies by FERC under the Federal Power Act, by the Commission under the Holding Company Act and by said states and as set forth in SECTION 5.5(a) of AEP's Disclosure Letter, neither AEP nor any of its Subsidiaries is subject to regulation as a public utility or a public service company (or similar designation) by any state in the United States or any municipality or other political subdivision of any state, by the United States or by any Governmental Authority of the United States or by any foreign country.

(b) *Approvals.* Except for the applicable requirements set forth in SECTION 5.5(b) of AEP's Disclosure Letter, no declaration, filing or registration with, no waiting period imposed by and no Permit or Order of, any Governmental Authority is required under any Law, Regulation or Order applicable to AEP or any of its Subsidiaries to permit AEP or Newco to execute, deliver or perform this Agreement or any instrument required hereby to be executed and delivered by either of them at the Closing, the failure to obtain which could reasonably be expected to have a Material Adverse Effect on AEP.

SECTION 5.6 *No Violation.* Assuming receipt of all Permits and Orders indicated as required in SECTION 5.5(b) and receipt of the Required AEP Vote, neither the execution and delivery by AEP or Newco of this Agreement or any instrument required hereby to be executed and delivered by either of them at the Closing nor the performance by AEP or Newco of their respective obligations hereunder or thereunder will (a) violate or breach the terms of or cause a default under, or result in the termination of, or accelerate the performance required by, or result in a right of termination, cancellation or acceleration of any obligation under, or result in the creation of any lien, security interest, charge or encumbrance upon, any of the properties or assets of AEP or any of its Subsidiaries under (i) any Law, Regulation, Permit or Order applicable to AEP or any of its Subsidiaries, (ii) the certificate of incorporation or bylaws or similar organizational documents of AEP or any of its Subsidiaries or (iii) any note, bond, mortgage, indenture, deed of trust, license, franchise, concession, lease, contract or agreement to which AEP or any of its Subsidiaries is a party or by which it or any of its properties or assets is bound, or (b) with the passage of time, the giving of notice or the taking of any action by a third Person, have any of the effects set forth in clause (a) of this SECTION, except in any such case for any matters described in clauses (i) and (iii) of this SECTION that could not reasonably be expected to have a material adverse effect upon the ability of AEP or Newco to perform their respective obligations under this Agreement or a Material Adverse Effect on AEP. Prior to the execution of this Agreement, the Board of Directors of AEP has taken all necessary action to cause this Agreement and the transactions contemplated hereby to be exempt from the provisions of SECTION 912 of the New York Law.

SECTION 5.7 *Reports.* (a) *Reports.* Since January 1, 1993, AEP and its Subsidiaries have filed or caused to be filed (i) all SEC Reports of AEP or any of its Subsidiaries required to be filed with the Commission and (ii) all other Reports of AEP or any of its Subsidiaries required to be filed with any other Governmental Authorities, including the FERC, the Commission (under the Holding Company Act), the NRC and State Regulatory Commissions, except where the failure to file any such Reports of AEP or any of its Subsidiaries could not reasonably be expected to have a Material Adverse Effect on AEP. AEP has made available to the Company a true and complete copy of each such SEC Report. The Reports of AEP and its Subsidiaries, including all those filed after the date of this Agreement and prior to the Effective Time, (i) were or will be prepared in all material respects in accordance with the requirements of applicable Law and (ii), in the case of the SEC Reports of AEP and its Subsidiaries, did not at the time they were filed, or will not at the time they are filed, contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

(b) *Financial Statements.* The AEP Consolidated Financial Statements and any consolidated financial statements of AEP (including any related notes thereto) contained in any SEC Reports of AEP or any of its Subsidiaries filed with the Commission after the date of this Agreement (i) have been or will have been prepared in accordance with the published Regulations of the Commission and in accordance with GAAP (except (A) to the extent required by changes in GAAP, (B) with respect to unaudited financial statements as permitted by Form 10-Q and (C), with respect to SEC Reports of AEP filed prior to the date of this Agreement, as may be indicated in the notes thereto) and (ii) fairly present the consolidated financial position of AEP and its Subsidiaries as of the respective dates thereof and the consolidated results of their operations and cash flows for the periods indicated (including, in the case of any unaudited interim financial statements, reasonable estimates of normal and recurring year-end adjustments).

(c) *No Omissions.* Except for matters disclosed in SECTION 5.7(c) of AEP's Disclosure Letter, or matters disclosed in AEP's SEC Reports filed with the Commission prior to the date hereof, there exist no liabilities or obligations of AEP and its Subsidiaries, whether accrued, absolute, contingent or threatened, that would be required to be reflected, reserved for or disclosed under GAAP in consolidated financial statements of AEP as of and for the period ended on the dates on which this representation and warranty is made or deemed to be made, other than (i) liabilities or obligations that are adequately reflected, reserved for or disclosed in AEP's Consolidated Financial Statements, (ii) liabilities or obligations incurred in the ordinary course of business of AEP consistent with past practice since September 30, 1997, (iii) liabilities or obligations the incurrence of which would not have been prohibited by SECTION 6.1 or 6.2(b) had such sections been in effect since September 30, 1997 and (iv) other liabilities and obligations that could not reasonably be expected to have a Material Adverse Effect on AEP.

SECTION 5.8 *No Material Adverse Effect; Conduct.* (a) *Material Adverse Changes.* Except as set forth in SECTION 5.8(a) of AEP's Disclosure Letter, since September 30, 1997, no event (other than any event that is of general application to the electric utility industry in the United States or the United Kingdom) has occurred that, individually or together with other similar events, has had, and to the Knowledge of AEP, no fact or condition (other than any fact or condition that is of general application to the electric utility industry in the United States or the United Kingdom) exists that could reasonably be expected to have, a Material Adverse Effect on AEP.

(b) *Proscribed Conduct.* Except as set forth in SECTION 5.8(b) of AEP's Disclosure Letter, during the period from September 30, 1997 to the date of this Agreement, neither AEP nor any of its Subsidiaries has failed to conduct its business in the ordinary course consistent with past practice, other than any conduct that would not have been prohibited by SECTION 6.1 or SECTION 6.2(b) had such sections been in effect since September 30, 1997.

SECTION 5.9 *Permits; Compliance.* (a) *General.* To the Knowledge of AEP, AEP and its Subsidiaries have obtained all Orders and Permits that are necessary to carry on their businesses as currently conducted, except for any such Orders or Permits that the failure to possess, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on AEP. All such Orders and Permits are in full force and effect, have not been violated in any respect that could reasonably be expected to have a Material Adverse Effect on AEP and no suspension, revocation or cancellation thereof has occurred or, to the Knowledge of AEP, been threatened and there is no action, proceeding or investigation pending or, to the Knowledge of AEP, threatened regarding suspension, revocation or cancellation of any of such Permits or Orders, except where the suspension, revocation or cancellation of such Permits or Orders could not reasonably be expected to have a Material Adverse Effect on AEP.

(b) *Cook Nuclear Plant.* A Subsidiary of AEP is the owner of the Cook Nuclear Plant. Except as set forth in SECTION 5.9(b) of AEP's Disclosure Letter, to the Knowledge of AEP, the operations of the Cook Nuclear Plant have at all times been conducted in compliance with applicable health, safety, regulatory and other legal requirements, except where the failure to be so in compliance in the aggregate could not reasonably be expected to have a Material Adverse Effect on AEP. Except as set forth in SECTION 5.9(b) of AEP's Disclosure Letter, to the Knowledge of AEP, the operations of the Cook Nuclear Plant are not the subject of any outstanding notices of violation or requests for information from the NRC or any other agency with jurisdiction over such facility. To the Knowledge of AEP, AEP maintains, and is in compliance with, an emergency plan designed to protect the health and safety of the public in the event of an unplanned release of radioactive materials from the Cook Nuclear Plant, and the NRC has determined that such plan is in compliance with its requirements. To the Knowledge of AEP, liability insurance to the full extent required by law for operating nuclear facilities remains in full force and effect with respect to the Cook Nuclear Plant, and the amount of such insurance has been approved by the NRC. To the Knowledge of AEP, plans for the decommissioning of the Cook Nuclear Plant, and for the storage of spent nuclear fuel, conform with the requirements of applicable law, and the owner of such facility has funded such plans to the extent required by Law.

SECTION 5.10 *Litigation; Compliance with Laws.* There are no actions, suits, investigations or proceedings (including any proceedings in arbitration) pending or, to the Knowledge of AEP, threatened against AEP or any of its Subsidiaries, at law or in equity, in any Court or before or by any Governmental Authority, except actions, suits or proceedings that (a) are fully and accurately disclosed in AEP's SEC Reports filed with the Commission prior to the date hereof, (b) are set forth in SECTION 5.10 or SECTION 5.14 of AEP's Disclosure Letter or (c) individually or, with respect to multiple actions, suits or proceedings that allege similar theories of recovery based on similar facts, in the aggregate, could not reasonably be expected to have a Material Adverse Effect on AEP. Except as set forth in SECTION 5.10 of AEP's Disclosure Letter, there are no Material claims pending or, to the Knowledge of AEP, threatened by any Persons against AEP or any of its Subsidiaries for indemnification pursuant to any statute, organizational document, contract or otherwise with respect to any action, suit, investigation or proceeding pending in any Court or before or by any Governmental Authority. Except as set forth in SECTION 5.10 of AEP's Disclosure Letter, AEP and its Subsidiaries are in substantial compliance with all applicable Laws and Regulations and are not in default with respect to any Order applicable to AEP or any of its Subsidiaries, except such events of noncompliance or defaults that, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on AEP.

SECTION 5.11 *Ownership of Company Common Stock.* Neither AEP nor any of its Affiliates "beneficially own" (as such term is defined for purposes of SECTION 13(d) of the Exchange Act) any shares of Company Common Stock.

SECTION 5.12 *Employee Benefit Plans.* (a) *Listing.* Each AEP Benefit Plan is listed in SECTION 5.12(a) of AEP's Disclosure Letter, including, with respect to Terminated AEP Benefit Plans, the date of termination. True and correct copies of each of the following have been made available to the Company with respect to each Current AEP Benefit Plan: (i) the three most recent annual reports (Form 5500) filed with the IRS, (ii) the plan document, (iii) the trust agreement, if any, (iv) the most recent summary plan description if required by ERISA, (v) the three most recent actuarial reports or valuations relating to each Current AEP Benefit Plan subject to Title IV of ERISA and (vi) the most recent determination letter, if any, issued by the IRS with respect to any Current AEP Benefit Plan intended to be qualified under SECTION 401 of the Code.

(b) *Material Adverse Changes.* With respect to each AEP Benefit Plan, no event has occurred and, to the Knowledge of AEP, there exists no condition or set of circumstances in connection with which AEP or any of its Subsidiaries could be subject to any liability under the terms of such AEP Benefit Plan, ERISA, the Code or any other applicable Law, other than any condition or set of circumstances that could not reasonably be expected to have a Material Adverse Effect on AEP.

(c) *Qualified Status of Current Plans.* Except as set forth in SECTION 5.12(c) of AEP's Disclosure Letter, each Current AEP Benefit Plan intended to be qualified under SECTION 401 of the Code (i) satisfies in form the requirements of such SECTION, (ii) has received a favorable determination letter from the IRS regarding such qualified status, (iii) has not, since receipt of the most recent favorable determination letter, been amended, and, (iv) to the Knowledge of AEP, has not been operated in a way that would adversely affect its qualified status.

(d) *No Termination of Current Plans.* Except as set forth in SECTION 5.12(d) of AEP's Disclosure Letter, there has been no termination or partial termination of any Current AEP Benefit Plan within the meaning of SECTION 411(d)(3) of the Code.

(e) *Terminated Plans.* Any Terminated AEP Benefit Plan intended to have been qualified under SECTION 401 of the Code received a favorable determination letter from the IRS with respect to its termination.

(f) *Claims.* There are no actions, suits or claims pending (other than routine claims for benefits) or, to the Knowledge of AEP, threatened against, or with respect to, any AEP Benefit Plan or its assets that could reasonably be expected to have a Material Adverse Effect on AEP and, to the Knowledge of AEP, no facts or circumstances exist that could give rise to any such actions, suits or claims.

(g) *Pending Matters.* To the Knowledge of AEP, there is no matter pending (other than routine qualification determination filings) with respect to any AEP Benefit Plan before the IRS, the Department of Labor, the PBGC or other Government Authority.

(h) *Timely Contributions.* All contributions required to be made to AEP Benefit Plans pursuant to their terms and the provisions of ERISA, the Code or any applicable Law have been timely made.

(i) *Current Plans Subject to Title IV of ERISA.* As to each Current AEP Benefit Plan subject to Title IV of ERISA, (i) there has been no event or condition that presents a significant risk of plan termination, (ii) no accumulated funding deficiency, whether or not waived, within the meaning of SECTION 302 of ERISA or SECTION 412 of the Code has been incurred, (iii) no reportable event within the meaning of SECTION 4043 of ERISA (for which the disclosure requirements of Regulation section 4043.1 et seq. promulgated by the PBGC have not been waived) has occurred within six years prior to the date of this Agreement, (iv) no notice of intent to terminate such Benefit Plan has been given under SECTION 4041 of ERISA, (v) no proceeding has been instituted under SECTION 4042 of ERISA to terminate such

Benefit Plan, (vi) no liability to the PBGC has been incurred (other than with respect to required premium payments) and (vii) the assets of such Benefit Plan equal or exceed the actuarial present value of the benefit liabilities, within the meaning of SECTION 4041 of ERISA, under such Benefit Plan, based upon reasonable actuarial assumptions and the asset valuation principles established by the PBGC.

(j) *Excess Parachute Payments.* Except as set forth in SECTION 5.12(j) of AEP's Disclosure Letter, in connection with the consummation of the transactions contemplated by this Agreement, no payments of money or other property, acceleration of benefit or provision of other rights have been or will be made under any Current AEP Benefit Plan that could be reasonably be expected to be nondeductible under SECTION 280G of the Code, whether or not some other subsequent action or event would be required to cause such payment, acceleration or provision to be triggered.

(k) *No Required Increase in Contributions.* The execution and delivery of this Agreement and the consummation of the transactions contemplated hereby will not (i) require AEP or any of its Subsidiaries to make a larger contribution to, or pay greater benefits or provide other rights under, any Current AEP Benefit Plan than it otherwise would, whether or not some other subsequent action or event would be required to cause such payment or provision to be triggered or (ii) create or give rise to any additional vested rights or service credits under any Current AEP Benefit Plan, whether or not some other subsequent action or event would be required to cause such creation or acceleration to be triggered.

(l) *Intentionally Omitted.*

(m) *Retiree Benefits.* Except as set forth in SECTION 5.12(m) of AEP's Disclosure Letter, no Current AEP Benefit Plan (other than an AEP Benefit Plan maintained outside the United States that is either fully insured or fully funded through a retirement plan) provides retiree medical or retiree life insurance benefits to any Person and neither AEP nor any of its Subsidiaries is contractually or otherwise obligated (whether or not in writing) to provide any Person with life insurance or medical benefits upon retirement or termination of employment, other than as required by the provisions of SECTIONs 601 through 608 of ERISA and SECTION 4980B of the Code.

(n) *Multiemployer Plans.* Except as set forth in SECTION 5.12(n) of AEP's Disclosure Letter, neither AEP nor any member of its Controlled Group contributes or has an obligation to contribute, and has not within six years prior to the date of this Agreement contributed, had an obligation to contribute, or had any other liability to a multiemployer plan within the meaning of SECTION 3(37) of ERISA. Neither AEP nor any member of its Controlled Group participate in any multiemployer plan with withdrawal liability on the date hereof which could reasonably be expected to have a Material Adverse Effect on AEP.

(o) *Collective Bargaining Contracts.* Except as set forth in SECTION 5.12(o) of AEP's Disclosure Schedule, (i) no collective bargaining agreement is being negotiated by AEP or any of its Subsidiaries, (ii) there is no pending or, to the Knowledge of AEP, threatened labor dispute, strike or work stoppage against AEP or any of its Subsidiaries that could reasonably be expected to have a Material Adverse Effect on AEP, (iii) to the Knowledge of AEP, neither AEP or any of its Subsidiaries nor any representative or employee of AEP or any of its Subsidiaries has in the United States committed any Material unfair labor practices in connection with the operation of the business of AEP and its Subsidiaries, and (i) there is no pending or, to the Knowledge of AEP, threatened charge or complaint against AEP or any of its Subsidiaries by the National Labor Relations Board or any comparable agency of any state of the United States.

SECTION 5.13 *Taxes.* (a) *Tax Returns and Taxes.* Except for such matters as could not reasonably be expected to have a Material Adverse Effect on AEP, (i) all Tax Returns that are required to be filed by or with respect to AEP or any of its Subsidiaries on or before the Effective Time have been or will be timely filed, (ii) all Taxes that are due and payable by AEP or any of its Subsidiaries on or before the Effective Time have been or will be timely paid in full or adequate reserves have been established for the payment of such Taxes, (iii) all withholding Tax requirements imposed on or with respect to AEP or any of its

Subsidiaries and that are required to be satisfied at or before the Effective Time have been or will be satisfied in full in all respects and (iv) no penalty, interest or other charge is or will become due with respect to the late filing of any such Tax Return or late payment of any Tax by AEP or any of its Subsidiaries.

(b) *Audits.* Except as set forth in SECTION 5.13(b) of AEP's Disclosure Letter, all Material Tax Retµrns required to be filed by AEP or any of its Subsidiaries have been audited (and such audit has become final) by the applicable Governmental Authority or the applicable statute of limitations has expired for the period covered by such Tax Returns.

(c) *Extension of Time.* Except as set forth in SECTION 5.13(c) of AEP's Disclosure Letter, there is not in force any extension of time with respect to the due date for the filing of any Material Tax Return required to be filed by AEP or any of its Subsidiaries or any waiver or agreement for any extension of time for the assessment or payment of any Tax due with respect to the period covered by any Tax Return filed, or required to be filed, by AEP or any of its Subsidiaries.

(d) *Claims.* No Material issues have been raised by any Taxing authority in connection with the audit or examination of any Tax Return filed, or required to be filed, by AEP or any of its Subsidiaries, and there is no claim against AEP or any of its Subsidiaries for any Taxes, and no assessment, deficiency or adjustment has been asserted or proposed with respect to any Tax Return, that, in either case, could reasonably be expected to have a Material Adverse Effect on AEP.

(e) *Affiliated Group.* Except as set forth in SECTION 5.13(e) of AEP's Disclosure Letter, none of AEP and its Subsidiaries, during the last ten years, has been a member of an affiliated group filing a consolidated Federal income Tax Return other than an affiliated group of which AEP is the common parent.

SECTION 5.14 *Environmental Matters.* Except for matters disclosed in SECTION 5.14 of AEP's Disclosure Letter, or matters disclosed in AEP's SEC Reports filed with the Commission prior to the date hereof, and except for matters that, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on AEP, (a) the properties, operations and activities of AEP and its Subsidiaries are in compliance with all applicable Environmental Laws; (b) AEP and its Subsidiaries and the properties and operations of AEP and its Subsidiaries are not subject to any existing, pending or, to the Knowledge of AEP, threatened action, suit, investigation, inquiry or proceeding by or before any Court or Governmental Authority under any Environmental Law; (c) all Permits, if any, required to be obtained or filed by AEP or any of its Subsidiaries under any Environmental Law in connection with the business of AEP and its Subsidiaries have been obtained or filed and are valid and currently in full force and effect; (d) to the Knowledge of AEP, there has been no release of any hazardous substance, pollutant or contaminant into the environment by AEP or its Subsidiaries or in connection with their properties or operations; (e) to the Knowledge of AEP, there has been no exposure of any Person or property to any hazardous substance, pollutant or contaminant in connection with the properties, operations and activities of AEP and its Subsidiaries; and (f) AEP and its Subsidiaries have made available to the Company all internal and external environmental audits and studies and all correspondence on substantial environmental matters (in each case relevant to AEP or any of its Subsidiaries) in the possession of AEP or its Subsidiaries.

SECTION 5.15 *Insurance.* AEP and its Subsidiaries own and are, and have been continuously since January 1, 1993, beneficiaries under all such insurance policies underwritten by reputable insurers that, as to risks insured, coverages and related limits and deductibles, are customary in the industries in which AEP and its Subsidiaries operate. Except as disclosed in SECTION 5.15 of AEP's Disclosure Letter, neither AEP nor any of it Subsidiaries has received any notice of cancellation or termination of any Material insurance policy as to which it is a named beneficiary. All Material insurance policies of AEP and its Subsidiaries are valid and enforceable against the underwriters thereof in accordance with their terms, except as the same may be limited by legal principles of general applicability governing the application and availability of equitable remedies.

SECTION 5.16 *Pooling; Tax Matters.* Neither AEP nor, to the Knowledge of AEP, any of its Affiliates has taken or agreed to take any action that would prevent the Merger from being treated as a "pooling of interests" in accordance with generally accepted accounting principles and the Regulations of the Commission or from constituting a reorganization within the meaning of section 368(a) of the Code.

SECTION 5.17 *Affiliates.* SECTION 5.17 of AEP's Disclosure Letter contains a true and complete list of all Persons who, to the Knowledge of AEP, may be deemed to be "affiliates" of AEP as such term is used under Rule 145 under the Securities Act, including all directors and executive officers of AEP.

SECTION 5.18 *Opinion of Financial Advisor.* AEP has received the opinion of Salomon Smith Barney on the date of this Agreement to the effect that the consideration to be paid by AEP in the Merger is fair, from a financial point of view, to AEP.

SECTION 5.19 *Brokers.* Except as set forth in SECTION 5.19 of AEP's Disclosure Letter, no broker, finder or investment banker (other than Salomon Smith Barney) is entitled to any brokerage, finder's or other fee or commission in connection with the transactions contemplated by this Agreement based upon arrangements made by or on behalf of AEP. Prior to the date of this Agreement, AEP has made available to the Company complete and correct copies of all agreements between AEP and Salomon Smith Barney pursuant to which such firm will be entitled to any payment relating to the transactions contemplated by this Agreement.

SECTION 5.20 *Vote Required.* The affirmative vote of holders of a majority of the outstanding shares of AEP Common Stock is the only vote of holders of any class or series of capital stock of AEP necessary to approve the amendment to the restated certificate of incorporation of AEP in order to increase the number of authorized shares of AEP Common Stock to be issued in the Merger (the "Charter Amendment"); and the affirmative vote of holders of shares of AEP Common Stock representing a majority of the total votes cast at a meeting of the holders of outstanding shares of AEP Common Stock is the only vote of the holders of any class or series of AEP capital stock necessary under the rules of the NYSE to approve the issuance of shares of AEP Common Stock to be issued in the Merger (the "Share Issuance"). Such votes of the holders of shares of AEP Common Stock necessary to approve the Charter Amendment and the Share Issuance are hereinafter collectively referred to as the "Required AEP Vote" and are the only votes of the holders of any class or series of capital stock of AEP or its Subsidiaries required to approve the Merger, this Agreement or the transactions contemplated hereby, except for the vote of AEP as the sole stockholder of Newco. AEP, in its capacity as sole stockholder of Newco, has approved this Agreement and the transactions contemplated hereby.

SECTION 5.21 *No Business Activities.* Newco was organized solely for the purpose of the transactions contemplated hereby and has not conducted any activities other than in connection with the organization of Newco, the negotiation and execution of this Agreement and the consummation of the transaction contemplated hereby. Newco has no Subsidiaries.

except (i) pursuant to any contract, agreement or other legal obligation of the Company or any of its Subsidiaries existing at the date of this Agreement, (ii) increases in salary payable or to become payable upon promotion to an office having greater operational responsibilities, (iii), in the case of severance or termination payments, pursuant to the severance policy of the Company or its Subsidiaries existing at the date of this Agreement, (iv) in the case of options, warrants, rights or Benefit Plans, amendments required by ERISA or other applicable law and (v) except with respect to the management employees of the Company who are parties to Change of Control Agreements with the Company on the date hereof, any such increase, grant, amendment, modification or action in the ordinary course of business consistent with past practice;

(ii) (A) enter into any employment or severance agreement with, any director, officer or employee, either individually or as part of a class of similarly situated persons or (B) establish, adopt or enter into any new Benefit Plan; except employment and severance agreements entered into for the benefit of any newly employed or promoted officers or employees, in which case, the terms of such agreements shall be reasonably consistent with those existing at the date of such employment and except for Company Benefit Plans relating to health and life insurance benefits established, adopted or entered into in the ordinary course of business consistent with past practice;

(iii) declare or pay any dividend on, or make any other distribution in respect of, outstanding shares of capital stock of the Company or any Significant Subsidiary, except (A) dividends declared and paid by the Company with respect to the outstanding Company Common Stock at approximately the same times and at a rate per share of Company Common Stock not to exceed the rate per share of Company Common Stock as were declared and paid during the year ending December 31, 1997 and (B) dividends and distributions by a wholly owned Subsidiary of the Company to the Company or another wholly owned Subsidiary of the Company and (C) dividends and distributions declared and paid with respect to outstanding shares of preferred stock or similar obligations of the Company's Subsidiaries;

(iv) (A) redeem, purchase or acquire any outstanding Equity Securities of the Company or any of its Significant Subsidiaries other than redemptions, repurchases and other acquisitions of Equity Securities in the ordinary course of business consistent with past practice and that will not cause a failure of the condition contained in Section 8.1(e) to be satisfied, including purchases, redemptions and other acquisitions (1) in connection with the administration of employee benefit, direct stock purchase and dividend reinvestment plans as in effect on the date hereof in the ordinary course of the operation of such plans, (2) required by the respective terms of any Equity Security, (3) in connection with the refunding of preferred Equity Securities or through the issuance of additional preferred Equity Securities or indebtedness, as the case may be, at a lower cost of funds (calculating such cost on an aggregate after-tax basis) or through the issuance of indebtedness not prohibited by Section 6.2(a)(xi), (4) of Company Common Stock in the open market to fund up to $10,000,000 in any fiscal year of any acquisitions not prohibited by Section 6.2(a)(vii), (5) in intercompany transactions and (6) by the Company or any of its wholly-owned Subsidiaries directly from any wholly-owned Subsidiary of the Company in exchange for capital contributions or loans to such Subsidiary); or (B) split, combine or reclassify the Company Common Stock or effect any recapitalization of the Company;

(v) offer, sell, issue or grant, or authorize the offering, sale, issuance or grant, of any Equity Securities of the Company or any of its Significant Subsidiaries; except issuances of (A) Company Common Stock (1) upon the exercise of Company stock options outstanding at the date of this Agreement in accordance with the terms thereof, (2) upon the expiration of any restrictions upon issuance of any grant existing at the date of this Agreement of restricted stock or stock bonus pursuant to the terms of any Benefit Plans of the Company or any of its Subsidiaries or (3) periodically pursuant to the terms of any Benefit Plans of the Company or any of its Subsidiaries; and (B) preferred stock or similar securities of any Subsidiary for the purpose of financing investments or capital expenditures not prohibited under this Agreement or refinancing existing indebtedness or preferred stock or similar obligations of such Subsidiary;

(vi) grant any Lien (other than Permitted Encumbrances) with respect to any shares of capital stock of, or other equity interests in, any Significant Subsidiary of the Company owned beneficially by the Company or any other Subsidiary of the Company;

(vii) acquire, by merging or consolidating with, by purchasing an equity interest in or a portion of the assets of, or in any other manner acquiring, any business or any corporation, partnership, association or other business organization or division thereof or otherwise acquire any assets of any other Person; except (A) the purchase of assets from suppliers or vendors in the ordinary course of business and consistent with past or then standard industry practice, (B) acquisitions of equity interests, assets (excluding the acquisition of assets permitted in clause (A) above) and businesses related to the core domestic and U.K. regulated businesses in which the Company and its Subsidiaries are currently engaged (the "Company Core Businesses") the fair market value of the total consideration (including the value of indebtedness (other than non-recourse indebtedness) or other liability acquired or assumed) for which does not exceed 105% of the amount budgeted by the Company for such acquisitions as set forth in Section 6.2(a)(vii) of the Company's Disclosure Letter and (C) in connection with a Company Permitted Transaction;

(viii) except in connection with Company Permitted Transactions or as required by Law, sell, lease, exchange or otherwise dispose of, or grant any Lien (other than a Permitted Encumbrance) with respect to, any of the assets of the Company or any of its Subsidiaries that are Material to the Company, except dispositions of assets other than generation assets and inventories in the ordinary course of business and consistent with past practice;

(ix) adopt any amendments to its charter or bylaws or other organizational documents that could reasonably be expected to have a material adverse effect on the ability of the Company to perform its obligations under this Agreement;

(x) (A) change any of its methods of accounting in effect at September 30, 1997, except as may comply with GAAP, (B) make or rescind any election relating to Taxes that are Material to the Company (other than any election that must be made periodically and that is made consistent with past practice) or (C) change any of its methods of reporting income or deductions for Federal income tax purposes from those employed in the preparation of the Federal income tax returns for the taxable year ending December 31, 1996, except, in the case of each of clauses (A), (B) and (C), as may be required by Law and, in the case of clause (C), for matters that could not reasonably be expected to have a Material Adverse Effect on the Company;

(xi) except in connection with a Company Permitted Transaction or as required by Law, incur any obligations for borrowed money or purchase money indebtedness that are Material to the Company, whether or not evidenced by a note, bond, debenture or similar instrument, except (A) drawings under credit lines existing at the date of this Agreement or renewals or replacements thereof, (B) obligations evidenced by debt securities issued by a Subsidiary of the Company for the purpose of financing investments or capital expenditures permitted under this Agreement or refinancing existing indebtedness or preferred stock obligations of such Subsidiary and (C) indebtedness incurred in the ordinary course of business consistent with past or then standard industry practice;

(xii) unless required by the terms thereof, release any third Person from its obligations under any existing standstill agreement or similar agreement whether included in a confidentiality agreement or otherwise;

(xiii) except in connection with a Company Permitted Transaction or as required by Law, enter into any Material Contract with any third Person (other than customers and vendors in the ordinary course of business) that provides for an exclusive arrangement with that third Person or is substantially more restrictive on the Company or any of its Subsidiaries or substantially less advantageous to the Company or any of its Subsidiaries than Material Contracts existing on the date hereof;

(xiv) except in connection with a Company Permitted Transaction or as required by Law, make capital and non-fuel operational and maintenance expenditures relating to the Company Core Businesses in excess of 105% of the amount budgeted by the Company for capital and non-fuel operational and maintenance expenditures as set forth in Section 6.2(a)(vii) of the Company's Disclosure Letter;

(xv) except pursuant to any contract, agreement or other legal obligation of the Company or any of its Subsidiaries existing at the date of this Agreement, make, or commit to make, any investments in, or loans or capital contributions to, or to undertake any guarantees or other obligations with respect to, any joint venture (whether organized as a corporation, partnership or other legal entity) in excess of 105% of the amount budgeted by the Company for such investments relating to the Company Core Businesses as set forth in Section 6.2(a)(vii) of the Company's Disclosure Letter or in connection with a Company Permitted Transaction; or

(xvi) agree in writing or otherwise to do any of the foregoing.

(b) *AEP Covenants.* AEP covenants and agrees that, except as expressly contemplated by this Agreement or Section 6.2(b) of AEP's Disclosure Letter or otherwise consented to in writing by the Company, which consent shall not be unreasonably withheld, from the date of this Agreement until the Effective Time, it will not do, and will not permit any of its Subsidiaries to do, any of the following:

(i) (A) increase the compensation payable to or to become payable to any director or executive officer; (B) grant any severance or termination pay; (C) amend or otherwise modify the terms of any outstanding options, warrants or rights, the effect of which shall be to make such terms more favorable to the holders thereof; (D) amend or take any other actions to increase the amount or accelerate the payment or vesting of any benefit under any Benefit Plan (including the acceleration of vesting, waiving of performance criteria or the adjustment of awards or any other actions permitted upon a change in control of such party or upon a filing under Section 13(d) or 14(d) of the Exchange Act with respect to such party); except (i) pursuant to any contract, agreement or other legal obligation of AEP or any of its Subsidiaries existing at the date of this Agreement, (ii) increases in salary payable or to become payable upon promotion to an office having greater operational responsibilities, (iii), in the case of severance or termination payments, pursuant to the severance policy of AEP or its Subsidiaries existing at the date of this Agreement, (iv) in the case of options, warrants, rights or Benefit Plans, amendments required by ERISA or other applicable law and (v) any (including incentive) increase, grant, amendment, modification or action in the ordinary course of business consistent with past practice;

(ii) (A) enter into any employment or severance agreement with, any director, officer or employee, either individually or as part of a class of similarly situated persons or (B) establish, adopt or enter into any new Benefit Plan; except (1) employment and severance agreements entered into for the benefit of any newly employed or promoted officers or employees, in which case, the terms of such agreements shall be reasonably consistent with those existing at the date of such employment, (2) that AEP may modify or enter into severance arrangements with management employees, which arrangements provide a level of severance benefits to such management employees generally comparable to the level of severance benefits which are, on the date of this Agreement, provided to similarly situated employees of the Company and (3) for AEP Benefit Plans relating to health and life insurance benefits established, adopted or entered into in the ordinary course of business consistent with past practice;

(iii) declare or pay any dividend on, or to make any other distribution in respect of, outstanding shares of capital stock of AEP or any Significant Subsidiary (other than Yorkshire), except (A) dividends declared and paid by AEP with respect to the outstanding AEP Common Stock at approximately the same times and rates and at a rate per share of AEP Common Stock not less than the rate per share of AEP Common Stock as were declared and paid during the year ended December 31, 1997 and (B) dividends and distributions by a wholly owned Subsidiary of AEP to AEP or another wholly owned Subsidiary of AEP and (C) dividends and distributions declared and paid with respect to outstanding shares of preferred stock or similar obligations of AEP's Subsidiaries.

(iv) (A) redeem, purchase or acquire, or offer to purchase or acquire, any outstanding Equity Securities of AEP or any of its Significant Subsidiaries other than redemptions, repurchases and other acquisitions of Equity Securities in the ordinary course of business consistent with past practice which will not cause a failure of the condition contained in Section 8.1(e) to be satisfied, including purchases, redemptions and other acquisitions (1) in connection with the administration of employee benefit; direct stock purchase and dividend reinvestment plans as in effect on the date hereof in the ordinary course of the operation of such plans, (2) required by the respective terms of any Equity Security, (3) in connection with the refunding of preferred Equity Securities or through the issuance of additional preferred Equity Securities or indebtedness, as the case may be, at a lower cost of funds (calculating such cost on an aggregate after-tax basis) or through the issuance of indebtedness not prohibited by Section 6.2(b)(xi), (4) of AEP Common Stock in the open-market to fund up to $10,000,000 in any fiscal year of any acquisitions not prohibited by Section 6.2(b)(vii), (5) in intercompany transactions and (6) by AEP or any of its wholly-owned Subsidiaries directly from any wholly-owned Subsidiary of AEP in exchange for capital contributions or loans to such Subsidiary; or (B) split, combine or reclassify AEP Common Stock or effect any recapitalization of AEP;

(v) offer, sell, issue or grant, or authorize the offering, sale, issuance or grant, of any Equity Securities of AEP or any of its Significant Subsidiaries; except issuances of (A) AEP Common Stock (1) upon the expiration of any restrictions upon issuance of any grant existing at the date of this Agreement of restricted stock or stock bonus pursuant to the terms of any Benefit Plans of AEP or any of its Subsidiaries or (2) periodically pursuant to the terms of any Benefit Plans of AEP or any of its Subsidiaries; (B) preferred stock or similar securities of any Subsidiary for the purpose of financing investments or capital expenditures not prohibited under this Agreement or refinancing existing indebtedness or preferred stock or similar obligations of such Subsidiary and (C) issuances of a number of shares of AEP Common Stock not in excess of 10% of the number of shares represented to be outstanding in Section 5.3 hereof;

(vi) grant any Lien (other than Permitted Encumbrances) with respect to any shares of capital stock of, or other equity interests in, any Significant Subsidiary of AEP owned beneficially by AEP or any other Subsidiary of AEP;

(vii) acquire, by merging or consolidating with, by purchasing an equity interest in or a portion of the assets of, or in any other manner acquiring, any business or any corporation, partnership, association or other business organization or division thereof or otherwise acquire any assets of any other Person; except (A) the purchase of assets from suppliers or vendors in the ordinary course of business and consistent with past or then standard industry practice and (B) acquisitions of equity interests, assets (excluding the acquisition of assets permitted in clause (A) above) and businesses related to the energy sector the fair market value of the total consideration (including the value of indebtedness (other than non-recourse indebtedness) or other liability acquired or assumed) for which does not exceed $2.5 billion in the aggregate (which amount shall be reduced by the amount permitted and expended for (x) capital expenditures (other than relating to the core domestic and United Kingdom regulated utility business in which AEP and its Subsidiaries are currently engaged (the "AEP Core Businesses")) pursuant to Section 6.2(b)(xiv) and (y) joint ventures pursuant to Section 6.2(b)(xv);

(viii) sell, lease, exchange or otherwise dispose of, or grant any Lien (other than a Permitted Encumbrance) with respect to, any of the assets of AEP or any of its Subsidiaries that are Material to AEP, except (A) dispositions of assets other than generation assets and inventories in the ordinary course of business and consistent with past practice, (B) divestitures of non-AEP Core Businesses and (C) except as required by Law;

(ix) adopt any amendments to its charter or bylaws or other organizational documents that could reasonably be expected to have a material adverse effect on the ability of AEP to perform its obligations under this Agreement;

(x) (A) change any of its methods of accounting in effect at September 30, 1997, except as may be required to comply with GAAP, (B) make or rescind any election relating to Taxes that are Material to AEP (other than any election that must be made periodically and that is made consistent with past practice) or (C) change any of its methods of reporting income or deductions for Federal income tax purposes from those employed in the preparation of the Federal income tax returns for the taxable year ending December 31, 1996, except, in the case of each of clauses (A), (B) and (C), as may be required by Law and, in the case of clause (C), for matters that could not reasonably be expected to have a Material Adverse Effect on AEP;

(xi) except as required by Law, incur any obligations for borrowed money or purchase money indebtedness that are Material to AEP, whether or not evidenced by a note, bond, debenture or similar instrument, except (A) drawings under credit lines existing at the date of this Agreement or renewals or replacements thereof, (B) obligations evidenced by debt securities issued by a Subsidiary of AEP for the purpose of financing investments or capital expenditures permitted under this Agreement or refinancing existing indebtedness or preferred stock obligations of such Subsidiary, (C) purchase money indebtedness as to which Liens may be granted as permitted by Section 6.2(b)(vi), (D) indebtedness incurred in the ordinary course of business consistent with past practice and (E) indebtedness not in excess of $2.0 billion in the aggregate (in addition to the aggregate amount budgeted for indebtedness by AEP as set forth in Section 6.2(b)(xi) of AEP's Disclosure Letter);

(xii) unless required by the terms thereof, release any third Person from its obligations under any existing standstill agreement or similar agreement whether included in a confidentiality agreement or otherwise;

(xiii) except as otherwise required by Law, enter into any Material Contract with any third Person (other than customers and vendors in the ordinary course of business) that provides for an exclusive arrangement with that third Person or is substantially more restrictive on AEP or any of its Subsidiaries or substantially less advantageous to AEP or any of its Subsidiaries than Material Contracts existing on the date hereof;

(xiv) other than with respect to the AEP Core Businesses or except as required by Law, make capital expenditures in excess of $2.5 billion less the amounts permitted and expended in connection with acquisitions and joint ventures pursuant to Section 6.2(b)(vii) and Section 6.2(b)(xv);

(xv) except pursuant to any contract, agreement or other legal obligation of AEP or its Subsidiaries existing at the date of this Agreement, make or commit to make, any investments in, or loans or capital contributions to, or to undertake any guarantees or other obligations with respect to, any joint venture in excess of $2.5 billion (which amount shall be reduced by any amounts permitted and expended for capital expenditures (other than with respect to the AEP Core Businesses)) and acquisitions as set forth in Section 6.2(b)(xiv) and 6.2(b)(vii); or

(xvi) agree in writing or otherwise to do any of the foregoing.

SECTION 6.3 *Access and Information.* AEP and the Company shall each, and shall each cause its Subsidiaries to, (i) afford to the other party and its officers, directors, employees, accountants, consultants, legal counsel, agents and other representatives (collectively, the "Representatives" of such party) reasonable access at reasonable times upon reasonable prior notice to the officers, employees, agents, properties, offices and other facilities of such party and its Subsidiaries and to their books and records and (ii) furnish promptly to the other party and its Representatives such information concerning the business, properties, contracts, records and personnel of the furnishing party and its Subsidiaries (including financial, operating and other data and information) as may be reasonably requested, from time to time, by or on behalf of the other party. All documents furnished pursuant to this Section 6.3 shall be subject to the Confidentiality Agreement.

ARTICLE VII

ADDITIONAL AGREEMENTS

SECTION 7.1 *Meeting of AEP Stockholders.* AEP shall, promptly after the date of this Agreement, take all actions necessary in accordance with Law, the rules of the NYSE and its certificate of incorporation and bylaws to convene a special meeting of AEP's stockholders for the purpose of obtaining the Required AEP Vote (together with any adjournments thereof, the "AEP Stockholders' Meeting"), and AEP shall consult with the Company in connection therewith. Subject to Section 7.19, AEP shall take all commercially reasonable action to solicit from stockholders of AEP proxies in favor of the Share Issuance and the Charter Amendment and to secure the Required AEP Vote and the Board of Directors of AEP shall recommend approval of the Share Issuance and the Charter Amendment by the stockholders of AEP.

SECTION 7.2 *Meeting of Company Stockholders.* The Company shall, promptly after the date of this Agreement, take all actions necessary in accordance with Law, the rules of the NYSE and its certificate of incorporation and bylaws to convene a special meeting of the Company's stockholders to consider approval and adoption of this Agreement and the Merger (together with any adjournments thereof, the "Company Stockholders' Meeting"), and the Company shall consult with AEP in connection therewith. Subject to Section 7.19, the Company shall take all commercially reasonable action to solicit from stockholders of the Company proxies in favor of the approval and adoption of this Agreement and the Merger and to secure the Required Company Vote and the Board of Directors of the Company shall recommend approval of the transactions contemplated by this Agreement by the stockholders of the Company.

SECTION 7.3 *Registration Statement; Joint Proxy Statement/Prospectus.* (a) *Joint Proxy Statement/Prospectus.* As promptly as practicable after the execution of this Agreement, the parties shall prepare and file with the Commission the registration statement on form S-4 to be filed with the Commission in connection with the issuance of shares of AEP common stock in the Merger (the "Registration Statement") and the joint proxy statement relating to the meetings of AEP's and the Company's stockholders to be held in connection with the Merger (together with any amendments thereof or supplements thereto effected prior to the effective date of the Registration Statement, the "Joint Proxy Statement/Prospectus"). The Joint Proxy Statement/Prospectus shall comply as to form in all material respects with the applicable provisions of the Securities Act and the Exchange Act and the Regulations thereunder. Each of the AEP Companies and the Company shall furnish all information concerning it and the holders of its capital stock as the other may reasonably request in connection with the preparation and filing of the Joint Proxy Statement/Prospectus. Each of the AEP Companies and the Company will use all commercially reasonable efforts to have or cause the Registration Statement to become effective as promptly as practicable, and shall take any action required to be taken under any applicable Federal or state securities Laws in connection with the issuance of shares of AEP Common Stock in the Merger (other than qualifying to do business in any jurisdiction in which they are currently not so qualified). As promptly as practicable after the Registration Statement shall have become effective, (x) AEP shall mail the Joint Proxy Statement/Prospectus to its stockholders entitled to notice of and to vote at the AEP

Stockholders' Meeting and (y) the Company shall mail the Joint Proxy Statement/Prospectus to its stockholders entitled to notice of and to vote at the Company Stockholders' Meeting.

(b) *Company Information.* The information supplied by the Company for inclusion or incorporation by reference in the Registration Statement shall not, at the time the Registration Statement is declared effective, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein not misleading. The information supplied by the Company for inclusion or incorporation by reference in the Joint Proxy Statement/Prospectus shall not, at the date of the mailing of the Joint Proxy Statement/Prospectus (or any supplement thereto) and at the time of the AEP Stockholders' Meeting or of the Company Stockholders' Meeting or at the Effective Time, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading. If at any time prior to the Effective Time any event or circumstance relating to the Company or any of its Subsidiaries, or its or their respective officers or directors, should be discovered by the Company that should be set forth in an amendment to the Registration Statement or a supplement to the Joint Proxy Statement/Prospectus, the Company shall promptly inform AEP. All documents that the Company is responsible for filing with the Commission in connection with the transactions contemplated herein shall comply as to form in all material respects with the applicable requirements of the Securities Act and the Regulations thereunder and the Exchange Act and the Regulations thereunder.

(c) *The AEP Companies Information.* The information supplied by the AEP Companies for inclusion or incorporation by reference in the Registration Statement shall not, at the time the Registration Statement is declared effective, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein not misleading. The information supplied by AEP for inclusion or incorporation by reference in the Joint Proxy Statement/Prospectus shall not, at the date of the mailing of the Joint Proxy Statement/Prospectus (or any supplement thereto), at the time of the AEP Stockholders' Meeting or the Company Stockholders' Meeting or at the Effective Time, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they are made, not misleading. If at any time prior to the Effective Time any event or circumstance relating to AEP or any of its Subsidiaries, or to their respective officers or directors, should be discovered by AEP that should be set forth in an amendment to the Registration Statement or a supplement to the Joint Proxy Statement/Prospectus, AEP shall promptly inform the Company. All documents that the AEP Companies are responsible for filing with the Commission in connection with the transactions contemplated hereby shall comply as to form in all material respects with the applicable requirements of the Securities Act and the Regulations thereunder and the Exchange Act and the Regulations thereunder.

SECTION 7.4 *Appropriate Action; Consents; Filings.* (a) *Applications.* Each of the Company and AEP shall consult with one another, coordinate with respect to, and use all commercially reasonable efforts (i) subject to Section 7.19, to take, or to cause to be taken, all appropriate action, and to do, or to cause to be done, all things necessary, proper or advisable under applicable Law or otherwise to consummate and make effective the transactions contemplated by this Agreement, (ii) to obtain from any Governmental Authorities any Permits or Orders required to be obtained by AEP or the Company or any of their Subsidiaries in connection with the authorization, execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby, including the Merger, (iii) to make all necessary filings, and thereafter make any other required submissions, with respect to this Agreement and the Merger required under (A) the Securities Act and the Exchange Act, and any other applicable Federal or state securities Laws, (B) the Holding Company Act, (C) the Federal Power Act, (D) the Atomic Energy Act, (E) the applicable State Regulatory Acts, (F) the HSR Act and (G) any other applicable Law; provided that AEP and the Company shall cooperate with each other in connection with the making of all such filings, including providing copies of all such documents to the nonfiling party and its advisors prior to filings and, if requested, shall accept all reasonable additions, deletions or changes suggested in connection therewith, and provided further that, except as otherwise expressly provided herein, each party shall retain discretion and control over its affairs. The Company and AEP shall furnish all information required for any application or other filing to be made pursuant to any applicable Law or any applicable Regulations of any Governmental Authority in connection with the transactions contemplated by this Agreement.

(b) *Regulatory Plans.* The Company and AEP have jointly retained Vinson & Elkins L.L.P. and Simpson Thacher & Bartlett to assist the parties in developing and implementing a collaborative regulatory plan in connection with the transactions contemplated hereby.

(c) *Cooperation.* AEP and the Company agree to cooperate and use all commercially reasonable efforts to resist or resolve any action including legislative, administrative or judicial action and to have vacated or overturned any Order of any Court or Governmental Authority that is in effect and that prevents or prohibits the consummation of the Merger or any other transactions contemplated by this Agreement; *provided, however,* that in no event shall either party take, or be required to take, any action that could reasonably be expected to have a Material Adverse Effect on AEP, the Company or the Combined Companies. Both parties shall consult on a reasonable and frequent basis regarding matters relating to the operations of AEP and the Company prior to Closing, provided, that, except as otherwise expressly set forth herein, AEP and the Company shall each retain discretion over their own affairs.

(d) *Third Party Consents.* (i) Each of the Company and AEP shall give (or shall cause their respective Subsidiaries to give) any notices to third Persons, and use, and cause their respective Subsidiaries to use, all commercially reasonable efforts to obtain any consents from third Persons (A) necessary, proper or advisable to consummate the transactions contemplated by this Agreement, (B) otherwise required under any contracts, licenses, leases or other agreements in connection with the consummation of the transactions contemplated hereby or (C) required to prevent a Material Adverse Effect on the Company or AEP from occurring prior to the Effective Time or a Material Adverse Effect on the Combined Companies from occurring after the Effective Time (the "Third Party Consents").

(ii) If any party shall fail to obtain any consent from a third Person described in subsection (d)(i) above, such party shall use all commercially reasonable efforts, and shall take any such actions reasonably requested by the other parties, to limit the adverse effect upon the Company and AEP, their respective Subsidiaries, and their respective businesses resulting, or which could reasonably be expected to result after the Effective Time, from the failure to obtain such consent.

SECTION 7.5 *Affiliates; Pooling; Tax Treatment.* (a) *Affiliates.* Each of the Company and AEP shall use all commercially reasonable efforts to cause Persons (other than Subsidiaries) who are, or who become "affiliates," as such term is used in Rule 145 under the Securities Act, of the Company or AEP, as the case may be, after the date of this Agreement but prior to the date of the Company Stockholders' Meeting or the AEP Stockholders' Meeting, as the case may be, to execute and deliver a letter agreement substantially in the form of Annex B or Annex C hereto, as the case may be, not later than 10 days prior to the date of such meeting.

(b) *Effective Registration Statement.* AEP shall not be required to maintain the effectiveness of the Registration Statement for the purpose of resale by stockholders of the Company who may be Affiliates of the Company pursuant to Rule 145 under the Securities Act.

(c) *Pooling.* Each party hereto shall use all commercially reasonable efforts to cause the Merger to be treated for financial accounting purposes as a Pooling Transaction, and shall not take, and shall use all commercially reasonable efforts to prevent any Affiliate of such party from taking, any actions which could prevent the Merger from being treated for financial accounting purposes as a Pooling Transaction.

(d) *Tax Reorganization.* Each party hereto shall use all commercially reasonable efforts to cause the Merger to qualify, and shall not take, and shall use all commercially reasonable efforts to prevent any Affiliate of such party from taking, any actions which could prevent the Merger from qualifying as a reorganization under the provisions of Section 368(a) of the Code.

SECTION 7.6 *Public Announcements.* AEP and the Company shall consult with each other before issuing any press release or otherwise making any public statements with respect to the Merger or this Agreement and shall not issue any such press release or make any such public statement prior to such consultation.

SECTION 7.7 *NYSE Listing.* AEP shall use all commercially reasonable efforts to cause the shares of AEP Common Stock to be issued in the Merger to be approved for listing (subject to official notice of issuance) on the NYSE prior to the Effective Time.

SECTION 7.8 *Company Rights Agreement.* The Company shall take all action (including, if necessary, amending such Rights Agreement) so that the execution, delivery and performance of this Agreement and the consummation of the Merger and the other transactions contemplated hereby do not and will not result in the grant of any rights to any Person under the Company Rights Agreement or enable or require any outstanding rights to be exercised, distributed or triggered.

SECTION 7.9 *Comfort Letters.* (a) *AEP Letter.* AEP shall use all commercially reasonable efforts to cause Deloitte & Touche L.L.P. to deliver a letter dated as of the date of mailing of the Joint Proxy Statement/Prospectus, and addressed to AEP and the Company, in form and substance reasonably satisfactory to the Company and customary in scope and substance for agreed upon procedures letters delivered by independent public accounts in connection with registration statements and proxy statements similar to the Joint Proxy Statement/Prospectus.

(b) *Company Letter.* The Company shall use all commercially reasonable efforts to cause Arthur Andersen LLP to deliver a letter dated as of the date of mailing of the Joint Proxy Statement/Prospectus, and addressed to the Company and AEP, in form and substance reasonably satisfactory to AEP and customary in scope and substance for agreed upon procedures letters delivered by independent public accountants in connection with registration statements and proxy statements similar to the Joint Proxy Statement/Prospectus.

SECTION 7.10 *Stock Options; Employee Benefit Plans.* (a) *Stock-Based Compensation.*

(i) *Stock Options.* AEP agrees to assume, effective as of the Effective Time, each option to purchase shares of Company Common Stock granted under the Company's 1992 Long-term Incentive Plan or Directors' Compensation Plan (an "Outstanding Option") (whether or not vested) which remains as of such time unexercised in whole or in part and to substitute AEP Common Stock as purchasable under such assumed option ("Assumed Option"), with such assumption and substitution to be effected as follows:

(A) The Assumed Option shall not give the optionee additional benefits which he did not have under the Outstanding Option before such assumption;

(B) The number of shares of AEP Common Stock purchasable under any Assumed Option shall be equal to the number of whole shares of AEP Common Stock that the holder of the Outstanding Option being assumed would have received upon consummation of the Merger had such Outstanding Option been exercised in full prior to the Merger;

(C) The per share option price of the Assumed Option shall be equal to the per share option price of the Outstanding Option divided by the Common Stock Exchange Ratio; and

(D) The Assumed Option shall provide the optionee with the same benefit rights which he had under the Outstanding Option before such assumption.

Notwithstanding the foregoing, in the case of any Outstanding Option to which section 421 of the Code applies by reason of the qualification under section 422 of the Code, the exercise price, the number of shares purchasable pursuant to such option and the terms and conditions of exercise of such option shall comply with section 424(a) of the Code. As soon as practicable after the Effective Time, AEP shall deliver to the holders of the Outstanding Options appropriate agreements evidencing its assumption of such options.

(ii) *Other Stock-Based Compensation.* Effective as of the Effective Time, AEP agrees to assume the Company's 1992 Long-Term Incentive Plan and Director's Compensation Plan with respect to any stock-based compensation (other than the Outstanding Options) payable in the form of Company Common Stock as a result of the Merger ("Other Compensation"), and to substitute shares of AEP Common Stock with respect to such assumed Other Compensation. The number of shares of AEP Common Stock issuable with respect to such Other Compensation shall be equal to the number of whole shares of AEP Common Stock that the holder of Other Compensation being assumed would have received upon consummation of the Merger had such Other Compensation been paid in full prior to the Merger.

On or prior to the Effective Time, the Company shall take or cause to be taken all such actions, reasonably satisfactory to AEP, as may be necessary or desirable in order to authorize the transactions contemplated by subsections (i) and (ii) above. Further, AEP shall take all corporate actions necessary to reserve for issuance a sufficient number of shares of AEP Common Stock for delivery upon exercise of the Company Outstanding Options or issuance of the Company Other Compensation assumed by AEP pursuant to subsections (i) and (ii) above. Prior to the Effective Time, AEP shall file one or more registration statements on Form S-8 (or any successor or other appropriate forms) with respect to the shares of AEP Common Stock issuable in respect to the Assumed Options or Other Compensation and AEP Common Stock issuable in respect of the Assumed Options or Other Compensation and AEP shall use its commercially reasonable efforts to cause such registration statement to become effective promptly after the Effective Time and to maintain the effectiveness of such registration statement (and maintain the current status of the prospectus or prospectuses contained herein) for so long as any Assumed Options remain outstanding and to comply with applicable state securities and blue sky laws. So long as any holder of an Assumed Options shall be subject to the reporting requirements under Section 16(a) of the Exchange Act, AEP shall have the Company's 1992 Long-Term Incentive Plan and Directors' Compensation Plan to be administered in a manner that complies with Rule 16b-3 promulgated under the Exchange Act.

(b) *Separate Company Plans.* From and after the Effective Time through July 1, 2002, AEP will continue or cause to be continued, without adverse change to any employee or former employee of the Company or any of its Subsidiaries, the Company Benefit Plans listed in Section 7.10(b) of the Company's Disclosure Letter, except that (i) any Company Common Stock investment fund offered under a Company Benefit Plan will be replaced by an AEP Common Stock investment fund or a traditional investment fund as determined by AEP (ii) premiums charged to participants may be increased under medical, dental, life, accidental death and dismemberment, and disability insurance plans (except that premiums charged to participants who retired from the Company or any of its Subsidiaries prior to 1993 (or survivors of such participants) may not be increased), and (iii) changes required by law, including changes required to maintain the qualified status of any Company Benefit Plan intended to be qualified under Section 401(a) of the Code, may be made. After July 1, 2002, AEP will provide the employees of the Company and its Subsidiaries with benefits that in the aggregate are at least as favorable as the benefits provided to similarly situated employees of AEP and its Subsidiaries. If, after July 1, 2002, an AEP Benefit Plan is made available to employees of the Company or any of its Subsidiaries, all periods of service with the Company and its Subsidiaries will be credited to such employees for all purposes of the AEP Benefit Plan, including the accrual of benefits and eligibility to receive benefits for which a specified period of service is required under the AEP Benefit Plan. No earlier than July 1, 2002, the Company's Cash Balance Retirement Plan shall be merged into a defined benefit pension plan maintained by AEP or one of its

Subsidiaries. The retirement benefit for employees of the Company or its Subsidiaries who become participants in such merged plan will be determined under the AEP pension plan formula for all years of service (including years of service with the Company and its Subsidiaries) but such retirement benefit will not be less than the benefit accrued under the Company's Cash Balance Retirement Plan determined immediately prior to such plan merger plus the benefit determined under the AEP pension plan formula for years of service beginning on the date of such plan merger. If employees of the Company or any of its Subsidiaries become participants in a health plan maintained by AEP or any of its Subsidiaries, all preexisting condition limitations under the AEP health plan for such employees will be waived. In addition, if such AEP health plan participation becomes effective as of any date other than the first day of a calendar year, such employees will receive credit under the AEP health plan for any co-payments and deductibles incurred by such employees in the same calendar year under the Company's Medical Plan.

(c) *Retiree and Disability Benefits.* From and after July 1, 2002, AEP will provide access to retiree medical and life insurance coverage for any employee or director of the Company or any of its Subsidiaries who retires or becomes disabled prior to July 1, 2002 and who was eligible for such coverage under plans of the Company and its Subsidiaries in effect on the date of such individual's retirement. Further, for any such employees or directors who retired or became disabled prior to 1993, such coverage shall be continued without adverse change to such retired or disables employees or directors. In addition, with respect to any such employee who becomes disabled before July 1, 2002, so long as such employee continues to satisfy the eligibility requirements for disability benefits under the Company's Disability Income Plan in effect on such date AEP will offer such disabled employee medical coverage without charge to such disabled employee.

(d) *Certain Nonqualified Arrangements.* From and after the Effective Time through July 1, 2002. AEP will maintain the Company's Supplemental Executive Retirement Plan and Executive Deferred Compensation Plan without adverse change to any employee participating in the Plan until all benefits have been paid in accordance with the terms of the Plan; provided, however, that no deferrals shall be permitted under such plan after the Effective Time. If the Company's Supplemental Executive Retirement Plan or Executive Deferred Savings Plan is terminated or otherwise discontinued after July 1, 2002, AEP will make available to the class of employees of the Company and its Subsidiaries who were eligible to participate in the Company's Supplemental Executive Retirement Plan or Executive Deferred Savings Plan any nonqualified deferred compensation plan or plans it maintains to supplement benefits in the AEP Benefit Plans that are qualified plans. In addition, employees of the Company and its Subsidiaries will be given credit for service with the Company and its Subsidiaries for all purposes of such supplemental plans, and the supplemental plans will assume the obligation of the Supplemental Executive Retirement Plan or the Executive Deferred Savings Plan, as applicable, to pay the benefits that have accrued under the Supplemental Executive Retirement Plan or the Executive Deferred Savings Plan at the time of such termination or discontinuance.

(e) *Memorial Gifts Program.* The Company will take all action necessary to terminate the Memorial Gifts Program as of the Effective Time; provided, however, that all then-existing commitments under such Program will not be adversely affected by such termination and will be honored in accordance with their terms.

(f) *Agreement by AEP.* AEP agrees to honor without modification or contest, and agrees to cause the Surviving Corporation to honor without modification or contest, and to make required payments when due under all Change of Control Agreements and all Retention Agreements, including any modifications to such Change of Control Agreements or Retention Agreements permitted by Section 6.2(a).

(g) The provisions of Sections 7.10(d) and (f) are intended to be for the benefit of, and shall be enforceable by, each Person entitled to benefits or payments thereunder and the heirs and representatives of such Person.

SECTION 7.11 *Indemnification of Directors and Officers.* (a) Until six years from the Effective Time, the certificate of incorporation and bylaws of the Company as the corporation surviving the Merger (in this Section 7.11 called the "Surviving Corporation") as in effect immediately after the Effective Time shall not be amended to reduce or limit the rights of indemnity afforded to the present and former directors and officers of the Company thereunder or as to the ability of the Company to indemnify such persons or to hinder, delay or make more difficult the exercise of such rights of indemnity or the ability to indemnify. The Surviving Corporation will at all times exercise the powers granted to it by its certificate of incorporation, its bylaws and applicable law to indemnify to the fullest extent possible the present and former directors, officers, employees and agents of the Company against claims made against them arising from their service in such capacities prior to the Effective Time.

(b) If any claim or claims shall, subsequent to the Effective Time and within six years thereafter, be made against any present or former director, officer, employee or agent of the Company based on or arising out of the services of such Person prior to the Effective Time in the capacity of such Person as a director, officer, employee or agent of the Company, the provisions of subsection (a) of this Section respecting the certificate of incorporation and bylaws of the Surviving Corporation shall continue in effect until the final disposition of all such claims.

(c) AEP hereby agrees after the Effective Time to guarantee the payment of the Surviving Corporation's indemnification obligations described in Section 7.11(a) up to an amount determined as of the Effective Time equal to (i) the fair market value of any assets of the Surviving Corporation or any of its Subsidiaries distributed to AEP or any of its Subsidiaries (other than the Surviving Corporation and its Subsidiaries), minus (ii) any liabilities of the Surviving Corporation or any of its Subsidiaries assumed by AEP or any of its Subsidiaries (other than the Surviving Corporation and its Subsidiaries), minus (iii) the fair market value of any assets of AEP or any of its Subsidiaries (other than the Surviving Corporation and its Subsidiaries) contributed to the Surviving Corporation or any of its Subsidiaries and (iv) plus any liabilities of AEP or any of its Subsidiaries (other than the Surviving Corporation and its Subsidiaries) assumed by the Surviving Corporation or any of its Subsidiaries.

(d) Notwithstanding subsection (a), (b) or (c) of this Section 7.11, AEP and the Surviving Corporation shall be released from the obligations imposed by such subsection if AEP shall assume the obligations of the Surviving Corporation thereunder by operation of Law or otherwise. Notwithstanding anything to the contrary in this Section 7.11, neither AEP nor the Surviving Corporation shall be liable for any settlement effected without its written consent, which shall not be unreasonably withheld.

(e) AEP shall cause to be maintained in effect until six years from the Effective Time the current policies of directors' and officers' liability insurance maintained by the Company (or substitute policies providing at least the same coverage and limits and containing terms and conditions that are not materially less advantageous) with respect to claims arising from facts or events which occurred before the Effective Time; *provided, however,* that in no event shall AEP or the Surviving Corporation be required to expend more than 200 percent of the greater of (i) current annual premiums and (ii) annual premiums for the year in which the Closing occurs paid by the Company for such insurance; *provided, further,* that, if AEP or the Surviving Corporation is unable to obtain insurance for any period for 200 percent of the greater of such annual premiums, then the obligation of AEP and the Surviving Corporation pursuant hereto shall be to obtain the best coverage reasonably available under the circumstances subject to the foregoing limitations on premiums.

(f) The provisions of this Section 7.11 are intended to be for the benefit of, and shall be enforceable by, each Person entitled to indemnification hereunder and the heirs and representatives of such Person.

(g) AEP shall not permit the Surviving Corporation to merge or consolidate with any other Person unless the Surviving Corporation shall ensure that the surviving or resulting entity assumes the obligations imposed by subsections (a), (b), (c) and (e) of this Section.

SECTION 7.12 *Newco.* Prior to the Effective Time, Newco shall not conduct any business or make any investments other than as specifically contemplated by this Agreement and will not have any assets (other than the minimum amount of cash required to be paid to Newco for the valid issuance of its stock to AEP).

SECTION 7.13 *Event Notices.* From and after the date of this Agreement until the Effective Time, each party hereto shall promptly notify the other party hereto of (i) the occurrence or nonoccurrence of any event the occurrence or nonoccurrence of which would be likely to cause any condition to the obligations of such party to effect the Merger and the other transactions contemplated by this Agreement not to be satisfied and (ii) the failure of such party to comply with any covenant or agreement to be complied with by it pursuant to this Agreement which would be likely to result in any condition to the obligations of such party to effect the Merger and the other transactions contemplated by this Agreement not to be satisfied. No delivery of any notice pursuant to this Section 7.13 shall cure any breach of any representation or warranty or any failure to comply with any covenant or agreement of such party contained in this Agreement or otherwise limit or affect the remedies available hereunder to the party receiving such notice.

SECTION 7.14 *Board of Directors.* At the Effective Time, the Board of Directors of AEP shall be expanded to fifteen members and reconstituted to include all then current board members of AEP, the Chairman of the Company on the date hereof, and four additional outside directors of the Company to be nominated by AEP.

SECTION 7.15 *Headquarters.* At and after the Effective Time, the principal corporate office of the Combined Companies shall be located in Columbus, Ohio; and the Combined Companies shall maintain a significant presence in the states currently served by the Company.

SECTION 7.16 *Rate Matters.* Each of the Company and AEP shall, and shall cause its Significant Subsidiaries to, discuss with the other any changes in its or its Significant Subsidiaries' rates or charges (other than automatic cost pass-through rate adjustment clauses), standards of service or accounting from those in effect on the date hereof and consult with the other prior to making any filing (or any amendment thereto), or effecting any agreement, commitment, arrangement or consent with governmental regulators, whether written or oral, formal or informal, with respect thereto (provided that except as otherwise expressly provided herein each party shall retain discretion and control over its affairs), and except as set forth in Section 7.16 of the Company's Disclosure Letter, no party will make any filing to change its rates or charges, standards of service or accounting that could reasonably be expected to have a Material Adverse Effect on the Combined Companies.

SECTION 7.17 *Coordination of Dividends.* Each of the Company and AEP shall coordinate with the other regarding the declaration and payment of any dividends in respect of the Company Common Stock and AEP Common Stock and the record dates and the payment dates relating thereto, it being the intention of the Company and AEP that holders of the Company Common Stock shall not receive two dividends, or fail to receive one dividend, for any single calendar quarter with respect to their shares of Company Common Stock and/or any shares of AEP Common Stock that any such holder receives in exchange therefor pursuant to the Merger.

SECTION 7.18 *Transition-Management.* As soon as practicable after the date hereof, the parties shall create a special transition management task force (the "Task Force"). The Task Force shall examine various alternatives regarding the manner in which to best organize and manage the business of the Combined Companies after the Effective Time, subject to applicable Law.

SECTION 7.19 *Acquisition Proposals.* Each of AEP and the Company agrees that neither it nor any of its Subsidiaries nor any of the officers and directors of it or its Subsidiaries shall, and that it shall direct and use its best efforts to cause its and its Subsidiaries' employees, agents and representatives (including any investment banker, attorney or accountant retained by it or any of its Subsidiaries) not to, directly or indirectly, initiate, solicit, encourage or otherwise facilitate (including by way of furnishing information) any inquiries or the making of any proposal or offer with respect to a merger, reorganization, share exchange, consolidation, business combination, recapitalization, liquidation, dissolution or similar transaction involving, or any purchase or sale of all or any significant portion of the assets or 10% or more of the equity securities of, it or any of its Subsidiaries that, in any such case, could reasonably be expected to interfere with the completion of the Merger or the other transactions contemplated by this Agreement (any such proposal or offer being hereinafter referred to as an "*Acquisition Proposal*"). Each of AEP and the Company further agrees that neither it nor any of its Subsidiaries nor any of the officers and directors of it or its Subsidiaries shall, and that it shall direct and use its best efforts to cause its and its Subsidiaries' employees, agents and representatives (including any investment banker, attorney or accountant retained by it or any of its Subsidiaries) not to, directly or indirectly, have any discussion with or provide any confidential information or data to any Person relating to an Acquisition Proposal, or engage in any negotiations concerning an Acquisition Proposal, or otherwise facilitate any effort or attempt to make or implement an Acquisition Proposal or accept an Acquisition Proposal. Notwithstanding the foregoing, the Board of Directors of AEP or the Company shall be permitted to (A) to the extent applicable, comply with Rule 14e-2(a) promulgated under the Exchange Act with regard to an Acquisition Proposal, (B) in response to an unsolicited bona fide written Acquisition Proposal by any Person, recommend such an unsolicited bona fide written Acquisition Proposal to its stockholders, or withdraw or modify in any adverse manner its approval or recommendation of this Agreement or (C) engage in any discussions or negotiations with, or provide any information to, any Person in response to an unsolicited bona fide written Acquisition Proposal by any such Person, if and only to the extent that, in any such case as is referred to in clause (B) or (C), (i) the Required AEP Vote or the Required Company Vote, as the case may be, shall not have been obtained, (ii) the Board of Directors of AEP or the Company, as the case may be, concludes in good faith that such Acquisition Proposal (x) in the case of clause (B) above would, if consummated, constitute a Superior Proposal or (y) in the case of clause (C) above could reasonably be expected to constitute a Superior Proposal, (iii) the Board of Directors of AEP or the Company, as the case may be, determines in good faith upon the basis of written advice of outside legal counsel that such action is necessary for such Board of Directors to act in a manner consistent with its fiduciary duties under applicable law, (iv) prior to providing any information or data to any Person in connection with an Acquisition Proposal by any such Person, the AEP Board of Directors or the Company Board of Directors, as the case may be, receives from such Person an executed confidentiality agreement containing customary terms and provisions and (v) prior to providing any information or data to any Person or entering into discussions or negotiations with any Person, the Board of Directors of AEP or the Board of Directors of the Company, as the case may be, notifies the other party immediately of such inquiries, proposals or offers received by, any such information requested from, or any such discussions or negotiations sought to be initiated or continued with, any of its representatives indicating, in connection with such notice, the name of such Person and the material terms and conditions of any proposals or offers. AEP and the Company agree that they will keep the other party informed, on a current basis, of the status and terms of any such proposals or offers and the status of any such discussions or negotiations. Each of AEP and the Company agrees that it will immediately cease and cause to be terminated any existing activities, discussions or negotiations with any parties conducted heretofore with respect to any Acquisition Proposal. Each of AEP and the Company agrees that it will take the necessary steps to promptly inform the individuals or entities referred to in the first sentence of this Section 7.19 of the obligations undertaken in this Section 7.19. Nothing in this Section 7.19 shall (x) permit either AEP or the Company to terminate this Agreement (except as specifically provided in Article IX hereof) or (y) affect any other obligation of AEP or the Company under this Agreement.

SECTION 7.20 *Workforce Matters.* Subject to applicable collective bargaining agreements, for a period of 2 years following the Effective Time, any reductions in workforce in respect of employees of the Combined Company and their Subsidiaries shall be made on a fair and equitable basis, in light of the circumstances and the objectives to be achieved, giving consideration to previous work history, job experience, and qualifications, without regard to whether employment prior to the Effective Time was with the Company or its Subsidiaries or AEP or its Subsidiaries, and any employees whose employment is terminated or jobs are eliminated by AEP or any of its Subsidiaries during such period shall be entitled to participate on a fair and equitable basis in the job opportunity and employment placement programs offered by the Combined Companies or any of their prospective Subsidiaries. Any workforce reductions carried out following the Effective Time by the Combined Companies and their Subsidiaries shall be done in accordance with all applicable collective bargaining agreements, and all laws and regulations governing the employment relationship and termination thereof including, without limitation, the Worker Adjustment and Retraining Notification Act and regulations promulgated thereunder, and any comparable state or local law. As provided generally in Section 10.7, nothing in this Section is intended to confer upon any Person (other than the parties hereto), including any current or future employee of AEP or the Company or any subsidiary of either of them, any right, benefit or remedy of any nature whatsoever.

ARTICLE VIII

CLOSING CONDITIONS

SECTION 8.1 *Conditions to Obligations of Each Party.* The respective obligations of each party to effect the Merger and the other transactions contemplated hereby shall be subject to the satisfaction at or prior to the Effective Time of the following conditions, any or all of which may be waived by a party with respect to its obligations, in whole or in part, to the extent permitted by applicable Law:

(a) *Effectiveness of the Registration Statement.* The Registration Statement shall have been declared effective by the Commission under the Securities Act; and no stop order suspending the effectiveness of the Registration Statement shall have been issued by the Commission and not withdrawn and no proceedings brought by the Commission for that purpose shall be pending.

(b) *Stockholder Approval.* (i) The Company shall have obtained the Required Company Vote in connection with the adoption of this Agreement by the stockholders of the Company and (ii) AEP shall have obtained the Required AEP Vote in connection with the approval of the Share Issuance and the Charter Amendment by the stockholders of AEP.

(c) *No Prohibiting Law, Regulation or Order.* No Court or Governmental Authority shall have enacted, issued, promulgated, enforced or entered any Law, Regulation or Order (whether temporary, preliminary or permanent) that is in effect and that has the effect of making the Merger illegal or otherwise prohibiting consummation of the Merger.

(d) *Required Orders.* All Orders necessary for the consummation of the Merger and the other transactions contemplated hereby shall have been obtained at or prior to the Effective Time and such Orders shall have become Final Orders and no Final Orders shall impose terms or conditions or qualifications that, individually or in the aggregate, could reasonably be expected to have a Material Adverse Effect on the Combined Companies.

(e) *Pooling of Interests.* Each of AEP and the Company shall have received a letter of its independent public accountants, dated the Closing Date, in form and substance reasonably satisfactory, in each case, to AEP and the Company, stating that the transactions effected pursuant to this Agreement will qualify as a pooling of interests transaction under GAAP and applicable Commission Regulations.

(f) *NYSE Listing.* The shares of AEP Common Stock to be issued pursuant to the Merger shall have been listed, subject to official notice of issuance, on the NYSE.

(g) *Divestiture Event.* There shall not have occurred and remain in effect a Divestiture Event with respect to either AEP or the Company.

SECTION 8.2 *Additional Conditions to Obligations of the AEP Companies.* The obligations of the AEP Companies to effect the Merger and the other transactions contemplated hereby shall be subject to the satisfaction at or prior to the Effective Time of the following conditions, any or all of which may be waived by the AEP Companies, in whole or in part, to the extent permitted by applicable Law:

(a) *Representations and Warranties.* Each of the representations and warranties of the Company contained in this Agreement that is qualified as to materiality shall be true and correct in all respects and each of those that is not so qualified as to materiality shall be true and correct in all material respects as of the date of this Agreement and as of the Closing as though made again at and as of the Closing (except for representations and warranties that expressly speak only as of a specific date or time other than the date hereof or the Closing Date which need only be true and correct as of such date), provided, that no representation or warranty of the Company shall be deemed to be untrue or incorrect as a result of the occurrence of a Divestiture Event or any change or effect arising out of or resulting from any foreign, federal or state legislative or regulatory action with respect to (i) the regulation or deregulation of the electric utility industry in such jurisdiction, or (ii) health or the environment, including the conservation or protection of the environment. The AEP Companies shall have received a certificate of the Chief Executive Officer and the Chief Financial Officer of the Company, dated the Closing Date, to such effect.

(b) *Agreements and Covenants.* The Company shall have performed or complied with, in all material respects, all agreements and covenants required by this Agreement to be performed or complied with by it at or prior to the Closing. The AEP Companies shall have received a certificate of the Chief Executive Officer and the Chief Financial Officer of the Company, dated the Closing Date, to such effect.

(c) *Tax Opinion.* AEP shall have received the opinion dated the Closing Date of Simpson Thacher & Bartlett to the effect that (i) the Merger will constitute a reorganization under section 368(a) of the Code, (ii) the Company, AEP and Newco will each be a party to that reorganization, and (iii) no gain or loss will be recognized by the Company, AEP or Newco by reason of the Merger. In rendering their opinion, such counsel may require and rely upon representations, including those contained in certificates of officers of the Company, Newco and AEP.

(d) *Investment Banker's Opinion.* AEP shall have received, on or prior to the date of mailing of the Joint Proxy Statement/Prospectus to the holders of AEP Common Stock, a written opinion from Salomon Smith Barney, dated the date of such mailing, confirming the opinion to which reference is made in Section 5.18.

(e) *Company Required Consents.* The Company Required Consents shall have been obtained.

SECTION 8.3 *Additional Conditions to Obligations of the Company.* The obligations of the Company to effect the Merger and the other transactions contemplated hereby shall be subject to the satisfaction at or prior to the Effective Time of the following conditions, any or all of which may be waived by the Company, in whole or in part, to the extent permitted by applicable Law:

(a) *Representations and Warranties.* Each of the representations and warranties of the AEP Companies contained in this Agreement that is qualified as to materiality shall be true and correct in all respects and each of those that is not so qualified as to materiality shall be true and correct in all material respects as of the date of this Agreement and as of the Closing as though made again at and as of the Closing (except for representations and warranties that expressly speak only as of a specific date or time other than the date hereof or the Closing Date which need only be true and correct as of such date), provided, that no representation or warranty of AEP shall be deemed to be untrue or incorrect as a result of the occurrence of a Divestiture Event or any change or effect arising out of or resulting from any foreign, federal or sate legislative or regulatory action with respect to (i) the regulation or deregulation of the electric utility industry in such jurisdiction, or (ii) health or the environment, including the conservation or protection of the environment. The Company shall have received a certificate of the Chief Executive Officer and the Chief Financial Officer of AEP, dated the Closing Date to such effect.

(b) *Agreements and Covenants.* The AEP Companies shall have performed or complied with, in all material respects, all agreements and covenants required by this Agreement to be performed or complied with by them at or prior to the Closing. The Company shall have received a certificate of the Chief Executive Officer and the Chief Financial Officer of AEP, dated the Closing Date, to such effect.

(c) *Tax Opinion.* The Company shall have received the opinion dated the Closing Date of Christy & Viener to the effect that (i) the Merger will constitute a reorganization under section 368(a) of the Code, (ii) AEP, the Company and Newco will each be a party to that reorganization and (iii) no gain or loss will be recognized by the stockholders of the Company upon the receipt of shares of AEP Common Stock in exchange for shares of Company Common Stock pursuant to the Merger except with respect to any cash received in lieu of fractional interests in shares of AEP Common Stock or cash received pursuant to statutory dissenters rights. In rendering their opinion, such counsel may require and rely upon representations, including those contained in certificates of officers of the Company, Newco and AEP.

(d) *Investment Banker's Opinion.* The Company shall have received, on or prior to the date of mailing of the Joint Proxy Statement/Prospectus to the holders of Company Common Stock, a written opinion from Morgan Stanley & Co. Incorporated, dated the date of such mailing, confirming the opinion to which reference is made in Section 4.18.

(e) *AEP Required Consents.* The AEP Required Consents shall have been obtained.

ARTICLE IX

TERMINATION, AMENDMENT AND WAIVER

SECTION 9.1 *Termination.* This Agreement may be terminated at any time prior to the Effective Time, whether before or after receipt of the AEP Required Vote or before or after receipt of the Company Required Vote:

(a) *Mutual Consent.* By mutual written consent of AEP and the Company;

(b) *Terminating Company Breach.* By AEP, upon two Business Days' prior written notice to the Company, upon a breach of any representation, warranty, covenant or agreement on the part of the Company set forth in this Agreement, or if any representation or warranty of the Company shall have become untrue, in either case such that the conditions set forth in Section 8.2(a) or Section 8.2(b) would not be satisfied (a "Terminating Company Breach"); *provided that,* if such Terminating Company Breach is curable by the Company through the exercise of commercially reasonable efforts, for so long as the Company continues to exercise such commercially reasonable efforts AEP may not terminate this Agreement under this Section 9.1(b);

(c) *Terminating AEP Breach.* By the Company, upon two Business Days' prior written notice to AEP, upon breach of any representation, warranty, covenant or agreement on the part of the AEP Companies (or either of them) set forth in this Agreement, or if any representation or warranty of the AEP Companies (or either of them) shall have become untrue, in either case such that the conditions set forth in Section 8.3(a) or Section 8.3(b) would not be satisfied (a "Terminating AEP Breach"); *provided that,* if such Terminating AEP Breach is curable by the AEP Companies through the exercise of their commercially reasonable efforts, for so long as the AEP Companies continue to exercise such commercially reasonable efforts the Company may not terminate this Agreement under this Section 9.1(c);

(d) *Divestiture Event.* By either AEP or the Company, upon two Business Days' prior written notice to the other, if there shall be any Divestiture Event; provided that, if such Divestiture Event is capable of being vacated, lifted or reversed on or before the Termination Date (as extended pursuant to Section 9.1(f) hereof) through the exercise of commercially reasonable efforts and for so long as the party whose assets are subject to the Divestiture Event continues to exercise such commercially reasonable efforts, such party seeking to terminate may not terminate this Agreement under this Section 9.1(d).

(e) *Law, Regulation or Order.* By either AEP or the Company, upon two Business Days' prior written notice to the other, if there shall be any Law or Regulation issued or adopted or any Order which is final and nonappealable preventing the consummation of the Merger, unless the party relying on such Law, Regulation or Order as a basis for termination under this Section 9.1(e) has not complied with its obligations under Section 7.4;

(f) *Termination Date.* By either AEP or the Company, by written notice to the other, if the Merger shall not have been consummated before December 31, 1999 ("Termination Date"); *provided, however,* that this Agreement may be extended by written notice of either AEP or the Company to a date not later than June 30, 2000, if the Merger shall not have been consummated as a result of the Company or the AEP Companies having failed by December 31, 1999 to satisfy the conditions set forth in Section 8.1(c) or Section 8.1(d) but all other conditions to the Closing shall be fulfilled; provided further, that, the right to terminate the Agreement under this Section 9.1(f) shall not be available to any party whose failure to fulfill any obligation under this Agreement has been the cause of, or resulted in, the failure of the Effective Time to occur on or before such date.

(g) *Stockholder Vote.* By either AEP or the Company, upon two Business Days' prior written notice to the other, if the transactions contemplated by this Agreement shall fail to receive the Required AEP Vote at the AEP Stockholders' Meeting or if this Agreement shall fail to receive the Required Company Vote at the Company Stockholders' Meeting;

(h) *AEP Fiduciary Out.* By AEP, at any time prior to receipt of the Required AEP Vote, upon two Business Days' prior written notice to the Company, if, the Board of Directors of AEP shall approve a Superior Proposal; provided, however, that (i) AEP shall have complied with Section 7.19, (ii) the Board of Directors of AEP shall have concluded in good faith, after giving effect to all concessions which may be offered by the Company pursuant to clause (iv) below, on the basis of the advice of its financial advisors and outside counsel, that such proposal is a Superior Proposal, (iii) the Board of Directors of AEP shall have concluded in good faith, after receipt of written advice of outside counsel, that notwithstanding all concessions which may be offered by the Company in negotiations entered into pursuant to clause (iv) below, such action is necessary for the AEP Board of Directors to act in a manner consistent with its fiduciary duties under applicable law; and (iv) prior to any such termination, AEP shall, and shall cause its respective financial and legal advisors to, negotiate with the Company to make such adjustments in the terms and conditions of this Agreement as would enable AEP to proceed with the transactions contemplated herein on such adjusted terms;

(i) *Company Fiduciary Out.* By the Company, at any time prior to receipt of the Required Company Vote, upon two Business Days' prior written notice to AEP, if, the Board of Directors of the Company shall approve a Superior Proposal; provided, however, that (i) the Company shall have complied with Section 7.19, (ii) the Board of Directors of the Company shall have concluded in good faith, after giving effect to all concessions which may be offered by AEP pursuant to clause (iv) below, on the basis of the advice of its financial advisors and outside counsel, that such proposal is a Superior Proposal, (iii) the Board of Directors of the Company shall have concluded in good faith, after receipt of the written advice of outside counsel, that notwithstanding all concessions which may be offered by AEP in negotiations entered into pursuant to clause (iv) below, such action is necessary for the Company Board of Directors to act in a manner consistent with its fiduciary duties under applicable law; and (iv) prior to any such termination, the Company shall, and shall cause its respective financial and legal advisors to, negotiate with AEP to make such adjustments in the terms and conditions of this Agreement as would enable the Company to proceed with the transactions contemplated herein on such adjusted terms;

(j) *AEP Change of Recommendation.* By the Company, upon two Business Days' prior written notice to AEP, if the Board of Directors of AEP or any committee thereof (A) shall withdraw or modify in any manner adverse to the Company its approval or recommendation of the Charter Amendment, the Share Issuance, this Agreement or the Merger, (B) shall fail to reaffirm such approval or recommendation upon the Company's request, (C) shall approve or recommend any Superior Proposal or (D) shall resolve to take any of the actions specified in clause (A), (B) or (C);

(k) *Company Change of Recommendation.* By AEP, upon two Business Days' prior written notice to the Company, if the Board of Directors of the Company or any committee thereof (A) shall withdraw or modify in any manner adverse to AEP its approval or recommendation of this Agreement or the Merger, (B) shall fail to reaffirm such approval or recommendation upon AEP's request, (C) shall approve or recommend any Superior Proposal or (D) shall resolve to take any of the actions specified in clause (A), (B) or (C); or

(l) *Third Party Acquisition.* By either AEP or the Company, by written notice to the other party, if (A) a third party acquires securities representing greater than 50% of the voting power of the outstanding voting securities of such other party or (B) individuals who as of the date hereof constitute the board of directors of such other party (together with any new directors whose election by such board of directors or whose nomination for election by the stockholders of such party was approved by a vote of a majority of the directors of such party then still in office who are either directors as of the date hereof or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of the board of directors of such party then in office.

The right of any party hereto to terminate this Agreement pursuant to this Section 9.1 shall remain operative and in full force and effect regardless of any investigation made by or on behalf of any party hereto, any Person controlling any such party or any of their respective officers, directors, representatives or agents, whether prior to or after the execution of this Agreement.

SECTION 9.2 *Effect of Termination.* Except as provided in Section 9.6 and Section 10.1 of this Agreement, in the event of the termination of this Agreement pursuant to Section 9.1, this Agreement shall forthwith become void, there shall be no liability on the part of the AEP Companies or the Company or any of their respective officers or directors to the other and all rights and obligations of any party hereto shall cease, except that nothing herein shall relieve any party from liability for any breach of this Agreement.

SECTION 9.3 *Amendment.* This Agreement may be amended by the parties hereto by action taken by or on behalf of their respective Boards of Directors at any time prior to the Effective Time; *provided, however,* that, after receipt of either the AEP Required Vote or the Company Required Vote, no amendment may be made which would reduce the amount or change the type of consideration into which each share of Company Common Stock shall be converted upon consummation of the Merger. This Agreement may not be amended except by an instrument in writing signed by the parties hereto.

SECTION 9.4 *Waiver.* At any time prior to the Effective Time, any party hereto may (a) extend the time for the performance of any of the obligations or other acts of the other party hereto, (b) waive any inaccuracies in the representations and warranties of the other party contained herein or in any document delivered pursuant hereto and (c) waive compliance by the other party with any of the agreements or, to the extent legally permissible, conditions contained herein. Any such extension or waiver shall be valid only if set forth in an instrument in writing signed by the party or parties to be bound thereby. For purposes of this Section 9.4, the AEP Companies shall be deemed to be one party.

SECTION 9.5 *Fees, Expenses and Other Payments.* Subject to Section 9.6, all Expenses incurred by the parties hereto shall be borne solely and entirely by the party which has incurred such Expenses; *provided, however,* that the share of all Expenses related to printing, filing and mailing the Registration Statement and the Joint Proxy Statement/Prospectus and all Commission and other regulatory filing fees incurred in connection with the Registration Statement and the Joint Proxy Statement/Prospectus allocable to the Company and to the AEP Companies as a group shall be 50% each; *and provided further* that AEP may, at its option and subject to Section 7.5(d), pay any Expenses of the Company.

SECTION 9.6 *Certain Damages, Payments and Expenses.* (a) *Damages Payable Upon Termination for Breach or Withdrawal of Approval.* If this Agreement is terminated pursuant to Section 9.1(h) or (i) (fiduciary out), Section 9.1(b) or (c) (breach), Section 9.1(j) or (k) (change of recommendation) or Section 9.1 (l) (acquisition of voting power or change of board), then the breaching party or party whose board has exercised its fiduciary out or changed its recommendation or whose voting stock has been acquired or whose board has changed, as the case may be, shall promptly (but not later than five Business Days after receipt of notice that the amount is due from the other party) pay to the other party, as liquidated damages and expense reimbursement, an amount in cash equal to $20 million (the "Termination Fee").

(b) *Other Termination Payments.* If (i) this Agreement is terminated pursuant to (A) Section 9.1(f) (expiration date), (B) Section 9.1(h) or (i) (fiduciary out), (C) Section 9.1(g) (failure to obtain shareholder approval), (D) Section 9.1(j) or (k) (change of recommendation) or (E) pursuant to Section 9.1(b) or (c) (breach); and (ii) at the time of such termination (or in the case of clause (i)(C) above, prior to the meeting of such party's shareholders) there shall have been an Acquisition Proposal involving the Company or AEP (as the case may be, the "Target Party") or any of its Affiliates which, at the time of such termination (or such meeting, as the case may be), shall not have been (x) rejected by the Target Party and its Board of Directors and (y) withdrawn by the third party; and (iii) within eighteen months of any such termination described in clause (i) above, the Target Party or any of its Affiliates becomes a Subsidiary of such offeror or a Subsidiary of an Affiliate of such offeror or accepts a written offer or enters into a written agreement to consummate or consummates an Acquisition Proposal with such offeror or an Affiliate thereof, then such Target Party (jointly and severally with its Affiliates), upon the signing of a definitive agreement relating to such Acquisition Proposal, or, if no such agreement is signed, then at the closing (and as a condition to the closing) of such Target Party becoming such a subsidiary or of such Acquisition Proposal, shall pay the Company or AEP, as the case may be, a termination fee equal to $225 million (the "Topping Fee") plus Expenses of such party not in excess of $20 million ("Out-of-Pocket Expenses"). If this Agreement is terminated by the Company or AEP pursuant to Section 9.1(l) (third party acquisition of voting power or change of board), then the Company or AEP, as the case may be, shall pay immediately the terminating party the Topping Fee plus Out-of-Pocket Expenses.

(c) *Expenses.* The Parties agree that the agreements contained in this Section 9.6 are an integral part of the transactions contemplated by this Agreement and constitute liquidated damages and not a penalty. If one party fails to promptly pay to the other any fee due hereunder, the defaulting party shall pay the costs and expenses (including legal fees and expenses) in connection with any action, including the filing of any lawsuit or other legal action, taken to collect payment, together with interest on the amount of any unpaid fee at the publicly announced prime rate of Citibank, N.A. from the date such fee was required to be paid.

(d) *Limitation of Fees.* Notwithstanding anything herein to the contrary, the aggregate amount payable to AEP and its Affiliates pursuant to Section 9.6(a) and Section 9.6(b) shall not exceed $245 million and the aggregate amount payable to the Company and its Affiliates pursuant to Section 9.6(a) and Section 9.6(b) shall not exceed $245 million.

(e) *Exclusive Remedy.* Subject to the following sentence, the payments required by Sections 9.6(a) and Section 9.6(b) shall constitute liquidated damages in full and complete satisfaction of, and shall be the sole and exclusive remedy for any loss, liability, damage or claim arising out of or in connection with the transactions contemplated by this Agreement, including any termination of this Agreement pursuant to Section 9.1. Notwithstanding the foregoing sentence, in the event of payment of the Termination Fee pursuant to Section 9.6(a), if (i) this Agreement is terminated by a party as a result of a willful breach of representation, warranty, covenant or agreement by the other party, and (ii) the Topping Fee is not paid, the nonbreaching party may pursue any remedies available to it at law or in equity and shall, in addition to the Termination Fee, be entitled to recover such additional amounts as such nonbreaching party may be entitled to receive at law or in equity.

ARTICLE X

GENERAL PROVISIONS

SECTION 10.1 *Effectiveness of Representations, Warranties and Agreements.* (a) *Effect of Investigation.* Except as set forth in Section 10.1(b) of this Agreement, the representations, warranties, covenants and agreements of each party hereto shall remain operative and in full force and effect regardless of any investigation made by or on behalf of any other party hereto, any Person controlling any such party or any of their officers, directors, representatives or agents whether prior to or after the execution of this Agreement.

(b) *Termination.* The representations and warranties in this Agreement shall terminate at the Effective Time and the representations, warranties, covenants and agreements shall terminate upon the termination of this Agreement pursuant to Article IX, except that the covenants and agreements set forth in the last sentence of Section 6.3, Sections 9.2, 9.5 and 9.6 and Article X hereof shall survive termination of this Agreement.

SECTION 10.2 *Notices.* All notices and other communications given or made pursuant hereto shall be in writing and shall be deemed to have been duly given upon receipt, if delivered personally, mailed by registered or certified mail (postage prepaid, return receipt requested) to the parties at the following addresses (or at such other address for a party as shall be specified by like changes of address) or sent by electronic transmission to the telecopier number specified below:

(a) *AEP.* If to any of the AEP Companies, to:

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
Attention: Donald M. Clements, Jr., Executive Vice President
Telecopier No.: 614-223-1552

with a copy to:

Simpson Thacher & Bartlett
425 Lexington Avenue
New York, New York 10017
Attention: James M. Cotter
Telecopier No.: (212) 455-2502

(b) *Company.* If to the Company, to:

Central and South West Corporation
1616 Woodall Rodgers Freeway
Dallas, Texas 75266-0164

Attention: Thomas V. Shockley, III, President
Telecopier No.: (214) 777-1528

with a copy to:

Vinson & Elkins L.L.P.
1001 Fannin
Houston, Texas 77002-6760
Attention: William E. Joor III
Telecopier No.: (713) 758-2346

SECTION 10.3 *Headings.* The headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement.

SECTION 10.4 *Severability.* If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any manner materially adverse to any party. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the parties hereto shall negotiate in good faith to modify this Agreement so as to effect the original intent of the parties as closely as possible in an acceptable manner to the end that transactions contemplated hereby are fulfilled to the extent possible.

SECTION 10.5 *Entire Agreement.* This Agreement (together with the Annexes, the Company's Disclosure Letter and AEP's Disclosure Letter) constitutes the entire agreement of the parties, and supersedes all prior agreements and undertakings, both written and oral, among the parties, with respect to the subject matter hereof, other than the Confidentiality Agreement which shall remain in full force and effect with respect to the subject matter thereof.

SECTION 10.6 *Assignment.* This Agreement shall not be assigned by operation of Law or otherwise.

SECTION 10.7 *Parties in Interest.* This Agreement shall be binding upon and inure solely to the benefit of each party hereto, and, except for the beneficiaries of the indemnities and covenants contained in Sections 7.11, 7.10(d) and 7.10(f) herein, nothing in this Agreement, express or implied, is intended to or shall confer upon any other Person any right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

SECTION 10.8 *Failure or Indulgence Not Waiver; Remedies Cumulative.* No failure or delay on the part of any party hereto in the exercise of any right hereunder shall impair such right or be construed to be a waiver of, or acquiescence in, any breach of any representation, warranty, covenant or agreement herein, nor shall any single or partial exercise of any such right preclude other or further exercise thereof or of any other right. All rights and remedies existing under this Agreement are cumulative to, and not exclusive to, and not exclusive of, any rights or remedies otherwise available.

SECTION 10.9 *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the Laws of the State of Delaware, regardless of the Laws that might otherwise govern under applicable principles of conflicts of law; *provided, however,* that any matter involving the internal corporate affairs of any party hereto shall be governed by the provisions of the state of its incorporation.

SECTION 10.10 *Counterparts.* This Agreement may be executed in multiple counterparts, and by the different parties hereto in separate counterparts, each of which when executed shall be deemed to be an original but all of which taken together shall constitute one and the same agreement.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed as of the date first written above by their respective officers thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

By /s/ E. LINN DRAPER, JR.

E. Linn Draper, Jr.
Chairman of the Board of Directors, President and Chief Executive Officer

AUGUSTA ACQUISITION CORPORATION

By: /s/ DONALD M. CLEMENTS, JR.

Donald M. Clements, Jr.
President

CENTRAL AND SOUTH WEST CORPORATION

By: /s/ E.R. BROOKS

E.R. Brooks
Chairman and Chief Executive Officer

SCHEDULE OF DEFINED TERMS

The following terms when used in the Agreement shall have the meanings set forth below unless the context shall otherwise require:

"Acquisition Proposal" shall have the meaning ascribed to such term in Section 7.19.

"Affiliate" shall, with respect to any Person, mean any other Person that controls, is controlled by or is under common control with the former.

"Agreement" shall mean the Agreement and Plan of Merger made and entered into as of December 21, 1997 among AEP, Newco and the Company, including any amendments thereto and each Annex (including this Annex A) and including AEP's Disclosure Letter and the Company's Disclosure Letter.

"APCo" shall mean Appalachian Power Company, a Virginia corporation.

"Atomic Energy Act" shall mean shall mean the Atomic Energy Act of 1954, as amended, and the Regulations promulgated thereunder.

"AEP" shall mean American Electric Power Company, Inc., a New York corporation, and its successors from time to time.

"AEP Benefit Plans" shall mean Benefit Plans with respect to AEP and its Subsidiaries.

"AEP Common Stock" shall mean the voting common stock, par value $6.50 per share, of AEP.

"AEP Companies" shall have the meaning ascribed to such term in the first paragraph of the Agreement.

"AEP Required Consents" shall mean any Third Party Consents relating to AEP the failure of which to obtain could reasonably be expected to have a Material Adverse Effect on the Combined Companies.

"AEP Stockholders' Meeting" shall have the meaning ascribed to such term in Section 7.1.

"AEP's Audited Consolidated Financial Statements" shall mean the condensed balance sheets of AEP and its Subsidiaries as of December 31, 1996, 1995 and 1994 and the related condensed statements of operations and cash flows for each of the three fiscal years in the three-year period ended December 31, 1996, together with the notes thereto, all as audited by Deloitte & Touche L.L.P., independent accountants, under their report with respect thereto dated February 25, 1997 and included in AEP's Annual Report on Form 10-K for the year ended December 31, 1996 filed with the Commission.

"AEP's Consolidated Financial Statements" shall mean AEP's Audited Consolidated Financial Statements and AEP's Unaudited Consolidated Financial Statements.

"AEP's Disclosure Letter" shall mean a letter of even date herewith delivered by AEP to the Company concurrently with the execution of the Agreement, which, among other things, shall identify exceptions to AEP's representations, warranties and covenants contained in this Agreement by specific section and subsection references.

"AEP's Unaudited Consolidated Financial Statements" shall mean the unaudited condensed balance sheet of AEP and its Subsidiaries as of September 30, 1997 and the related condensed statements of operations and cash flows for the three-month periods and nine-month periods ended September 30. 1996 and September 30, 1997, together with the notes thereto, included in AEP's Quarterly Report on Form 10-Q for the quarter ended September 30, 1997 filed with the Commission.

"Benefit Plans" shall mean, with respect to a specified Person, any employee pension benefit plan (whether or not insured), as defined in Section 3(2) of ERISA, any employee welfare benefit plan (whether or not insured) as defined in Section 3(1) of ERISA, any plans that would be employee pension benefit plans or employee welfare benefit plans if they were subject to ERISA, such as foreign plans and plans for directors, any stock bonus, stock ownership, stock option, stock purchase, stock appreciation rights, phantom stock, severance, employment, change-in-control, deferred compensation and any bonus or incentive compensation plan, agreement, program or policy (whether qualified or nonqualified, written oral), sponsored, maintained or contributed to by the specified Person or any of its Subsidiaries for the benefit of any of the present or former directors, officers, employees, agents, consultants or other similar representatives providing services to or for the specified Person or any of its Subsidiaries in connection with such services or any such plans which have been so sponsored, maintained, or contributed to within six years prior to the date of the Agreement; *provided, however*, that such term shall not include (a) routine employment policies and procedures developed and applied in the ordinary course of business and consistent with past practice, including wage, vacation, holiday and sick or other leave policies, (b) workers compensation insurance and (c) directors and officers liability insurance.

"Business Day" means any day other than a day on which banks in the State of Texas or the State of New York are authorized or obligated to be closed.

"Certificate of Merger" shall have the meaning ascribed to such term in Section 2.2.

"Charter Amendment" shall have the meaning ascribed to such term in Section 5.20.

"Change of Control Agreements" shall mean the change in control or severance agreements identified as such in Section 4.12(j) of the Company's Disclosure Letter.

"Closing" shall mean a meeting, which shall be held in accordance with Section 3.3, of all Persons interested in the transactions contemplated by the Agreement at which all documents deemed necessary by the parties to the Agreement to evidence the fulfillment or waiver of all conditions precedent to the consummation of the transactions contemplated by the Agreement are executed and delivered.

"Closing Date" shall mean the date of the Closing as determined pursuant to Section 3.3.

"Code" shall mean the Internal Revenue Code of 1986, as amended, and the rules and regulations promulgated thereunder.

"Combined Companies" shall mean, before the Merger, the AEP Companies (together with all of their Subsidiaries) and the Company (together with all of its Subsidiaries) considered as a single business enterprise as if the Merger had been consummated immediately prior to the time of consideration, and after the Merger shall mean AEP (together with its Subsidiaries).

"Commission" shall mean the Securities and Exchange Commission, a Governmental Authority of the United States Government, and its successors from time to time.

"Common Stock Exchange Ratio" shall mean 0.60, as adjusted pursuant to the second sentence of Section 3.1(a) of the Agreement.

"Company" shall mean Central and South West Corporation, a Delaware corporation, and its successors from time to time.

"Company Benefit Plans" shall mean Benefit Plans with respect to the Company and its Subsidiaries.

"Company Common Stock" shall mean the common stock, par value $3.50 per share, of the Company.

"Company Permitted Transactions" shall mean (i) those transactions described in Section 6.1 of the Company's Disclosure Letter and (ii) individual transactions not otherwise permitted by Section 6.2(a) the total investment (including debt and equity and other liability acquired or assumed) with respect to which does not exceed $50 million per annum or $150 million per annum when aggregated with all other such transactions, provided that no transactions entered into in reliance on this clause (ii) shall involve a total investment (including debt and equity and other liability acquired or assumed) in excess of $75 million per annum in any one country.

"Company Required Consents" shall mean any Third Party Consents relating to the Company the failure of which to obtain could reasonably be expected to have a Material Adverse Effect on the Combined Companies.

"Company Stockholders' Meeting" shall have the meaning ascribed to such term in Section 7.2.

"Company's Audited Consolidated Financial Statements" shall mean the condensed balance sheets of the Company and its Subsidiaries as of December 31, 1996, 1995 and 1994 and the related condensed and combined statements of operations and cash flows for each of the three fiscal years in the three-year period ended December 31, 1996, together with the notes thereto, all as audited by Arthur Andersen LLP, independent accountants, under their report with respect thereto dated February 28, 1997 and included in the Company's Annual Report on Form 10-K for the year ended December 31, 1996 filed with the Commission.

"Company's Consolidated Financial Statements" shall mean the Company's Audited Consolidated Financial Statements and the Company's Unaudited Consolidated Financial Statements.

"Company's Disclosure Letter" shall mean a letter of even date herewith delivered by the Company to the AEP Companies concurrently with the execution of the Agreement, which, among other things, shall identify exceptions to the Company's representations, warranties and covenants contained in this Agreement by specific section and subsection references.

"Company's Rights Agreement" shall mean that certain Rights Agreement entered into or to be entered into between the Company and a rights agent, substantially in the form previously filed with the Commission except for any amendments or modifications thereto contemplated in the Agreement.

"Company's Unaudited Consolidated Financial Statements" shall mean the unaudited condensed balance sheet of the Company and its Subsidiaries as of September 30, 1997 and the related condensed statements of operations and cash flows for the three-month periods and nine-month periods ended September 30, 1996 and September 30, 1997, together with the notes thereto, included in the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1997 filed with the Commission.

"Confidentiality Agreement" shall mean that certain confidentiality agreement between AEP and the Company dated October 17, 1997, as amended.

"Control" (including the terms "controlled," "controlled by" and "under common control with") shall mean the possession, directly or indirectly or as trustee or executor, of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of stock or as trustee or executor, by contract or credit arrangement or otherwise.

"Controlled Group" shall mean any organization which is a member of a controlled group of organizations within the meaning of Code sections 414(b), (c), (m) or (o).

"Cook Nuclear Plant" shall mean the Donald C. Cook nuclear plant located in Bridgman, Michigan.

"Court" shall mean any court or arbitration tribunal of the United States, any foreign country or any domestic or foreign state, and any political subdivision thereof, and shall include the European Court of Justice.

"CP&L" shall mean Central Power and Light Company, a Texas corporation and a Subsidiary of the Company.

"CSPCo" shall mean Columbus Southern Power Company, an Ohio corporation.

"Current AEP Benefit Plans" shall mean Benefit Plans that are sponsored, maintained, or contributed to by AEP or any of its Subsidiaries as of the date of the Agreement.

"Current Company Benefit Plans" shall mean Benefit Plans that are sponsored, maintained, or contributed to by the Company or any of its Subsidiaries as of the date of the Agreement.

"Delaware Law" shall mean the General Corporation Law of the State of Delaware.

"Divestiture Event" shall mean any Law, Regulation or Order adopted or issued by a Governmental Authority that requires the divestiture of a substantial portion of the generating assets of the Company and its Subsidiaries, taken as a whole, or AEP and its Subsidiaries, taken as a whole.

"Domestic Public Utility Company" shall mean a company that provides electric energy directly to retail customers under rates, terms and conditions determined by a State Regulatory Commission; provided that no company shall be a Domestic Public Utility Company solely by reason of engaging in power marketing or brokering or the wholesale sale of electric energy.

"Effective Time" shall mean the date and time of the completion of the filing of the Certificate of Merger with the Secretary of State of the State of Delaware in accordance with Section 2.2.

"Environmental Law or Laws" shall mean any and all laws, statutes, ordinances, rules, regulations, or orders of any Governmental Authority pertaining to health or the environment currently in effect and applicable to a specified Person and its Subsidiaries, including the Clean Air Act, as amended, the Comprehensive Environmental, Response, Compensation, and Liability Act of 1980 ("CERCLA"), as amended, the Federal Water Pollution Control Act, as amended, the Occupational Safety and Health Act of 1970, as amended, the Resource Conservation and Recovery Act of 1976 ("RCRA"), as amended, the Safe Drinking Water Act, as amended, the Toxic Substances Control Act, as amended, the Hazardous & Solid Waste Amendments Act of 1984, as amended, the Superfund Amendments and Reauthorization Act of 1986, as amended, the Hazardous Materials Transportation Act, as amended, the Oil Pollution Act of 1990, as amended ("OPA"), any state or local Laws implementing the foregoing Federal Laws, and all other environmental conservation or protection Laws. For purposes of the Agreement, the terms "hazardous substance" and "release" have the meanings specified in CERCLA; *provided, however,* that to the extent the Laws of the state or locality in which the property is located establish a meaning for "hazardous substance" or "release" that is broader than that specified in either CERCLA or RCRA, such broader meaning shall apply, and the term "hazardous substance" shall include all dehydration and treating wastes, waste (or spilled) oil, and waste (or spilled) petroleum products, and (to the extent in excess of background levels) radioactive material, even if such are specifically exempt from classification as hazardous substances pursuant to CERCLA or RCRA or the analogous statutes of any jurisdiction applicable to the specified Person or its Subsidiaries or any of their respective properties or assets.

"ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended, and the Regulations promulgated thereunder.

"Equity Securities" shall mean, with respect to a specified Person, any shares of capital stock of, or other equity interests in, or any securities that are convertible into or exchangeable for any shares of capital stock of, or other equity interests in, or any outstanding options, warrants or rights of any kind to acquire any shares of capital stock of, or other equity interests in, such Person.

"Exchange Act" shall mean the Securities Exchange Act of 1934 and the Regulations promulgated thereunder.

"Exchange Agent" shall mean a bank or trust company having a net worth in excess of $100 million designated and appointed to act in the capacities required thereof under Section 3.2.

"Exchange Fund" shall mean the fund of AEP Common Stock and cash in lieu of fractional interests and dividends and distributions, if any, with respect to such shares of AEP Common Stock established at the Exchange Agent pursuant to Section 3.2.

"Expenses" shall mean all reasonable out-of-pocket expenses (including all fees and expenses of counsel, accountants, investment bankers, experts and consultants to a party hereto and its affiliates) incurred by a party or on its behalf in connection with or related to the authorization, preparation, negotiation, execution and performance of the Agreement, the preparation, printing, filing and mailing of the Registration Statement, Joint Proxy Statement/Prospectus, the solicitation of stockholder approvals and all other matters related to the consummation of the transactions contemplated hereby.

"Federal Power Act" shall mean the Federal Power Act, as amended, and the Regulations promulgated thereunder.

"FERC" shall mean the Federal Energy Regulatory Commission, a Governmental Authority of the United States Government, and its successors from time to time.

"Final Order" shall mean an Order that has not been reversed, stayed, enjoined, set aside, annulled or suspended, with respect to which any waiting period prescribed by Law before the transactions contemplated hereby may be consummated has expired (but without the requirement for expiration of any applicable rehearing or appeal period), and as to which all conditions to the consummation of such transactions prescribed by Law, Regulation or Order have been satisfied.

"Foreign Utility Company" shall mean a foreign utility company as defined in section 33(a)(3) of the Holding Company Act.

"GAAP" shall mean accounting principles generally accepted in the United States consistently applied by a specified Person.

"Governmental Authority" shall mean any governmental or regulatory agency or authority (other than a Court but including a stock exchange or other self-regulatory body) of or within the United States, any foreign country, or any domestic or foreign state, and any political subdivision thereof, and shall include any multinational authority having governmental or quasi-governmental powers.

"Holding Company Act" shall mean the Public Utility Holding Company Act of 1935, as amended, and the Regulations promulgated thereunder.

"HSR Act" shall mean the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the Regulations promulgated thereunder.

"I&M" shall mean Indiana Michigan Power Company, an Indiana corporation.

"IRS" shall mean the Internal Revenue Service, a Governmental Authority of the United States Government, and its successors from time to time.

"Joint Proxy Statement/Prospectus" shall have the meaning ascribed to such term in Section 7.3(a).

"KEPCo" shall mean Kentucky Power Company, a Kentucky corporation.

"Knowledge" shall mean, with respect to either the Company or AEP, the actual knowledge of any executive officer of such party after reasonable inquiry.

"KPC" shall mean Kingsport Power Company, a Virginia corporation.

"Law" shall mean all laws, statutes, ordinances, rules and regulations of the United States, any foreign country, or any domestic or foreign state, and any political subdivision or agency thereof, including all decisions of Courts having the effect of law in each such jurisdiction.

"Lien" shall mean any mortgage, pledge, security interest, encumbrance, lien or charge of any kind (including any agreement to give any of the foregoing), any conditional sale or other title retention agreement, any lease in the nature thereof or the filing of or agreement to give any financing statement under the Uniform Commercial Code of any jurisdiction.

"Material" shall mean material to the business, condition (financial or otherwise) or results of operations or prospects of a specified Person and its subsidiaries, if any, taken as a whole; *provided, however*, that, as used in this definition the word "material" shall have the meaning accorded thereto in Section 11 of the Securities Act.

"Material Contract" shall mean each contract, lease, indenture, agreement, arrangement or understanding to which a specified Person or any of its Subsidiaries is a party or to which any of the assets or operations of such specified Person or any of its Subsidiaries is subject that is of a type that would be required to be included as an exhibit to a registration statement on Form S-1 pursuant to Paragraph (2), (4) or (10) of Item 601(b) of Regulation S-K under the Securities Act if such a registration statement were to be filed by such Person under the Securities Act on the date of determination.

"Material Adverse Effect" shall mean any change or effect that is material and adverse to the business, condition (financial or otherwise) or results of operations or prospects of a specified Person and its subsidiaries, if any, taken as a whole; *provided, however*, that, as used in this definition the word "material" shall have the meaning accorded thereto in Section 11 of the Securities Act.

"Merger" shall have the meaning ascribed to such term in Section 2.1 of the Agreement.

"Newco" shall mean Augusta Acquisition Corporation, a Delaware corporation and a wholly-owned Subsidiary of AEP formed for the sole purpose of affecting the Merger.

"New York Law" shall mean the New York Business Corporation Law.

"NRC" shall mean the Nuclear Regulatory Commission, a Governmental Authority of the United States Government, and its successors from time to time.

"NYSE" shall mean the New York Stock Exchange, Inc.

"OPCo" shall mean Ohio Power Company, an Ohio corporation.

"Operating Company" shall have the meaning ascribed to such term in Section 4.9(b).

"Order" shall mean any judgment, order or decree of any Court or Governmental Authority, Federal, foreign, state or local. Any reference in the Agreement to the "receipt" or "obtaining" of any Order shall mean making such declarations, filings or registrations; giving such notices; obtaining such consents or approvals; and having such waiting periods expire as are necessary to avoid a violation of Law.

"Out-of-Pocket Expenses" shall have the meaning ascribed to such term in Section 9.6(b).

"PBGC" shall mean the Pension Benefit Guaranty Corporation.

"Permit" shall mean any and all permits, licenses, authorizations, orders, consents, certificates, registrations or other approvals granted by any Governmental Authority. Any reference in the Agreement to the "receipt" or "obtaining" of any Permit shall mean making such declarations, filings or registrations; giving such notices; obtaining such consents or approvals; and having such waiting periods expire as are necessary to avoid a violation of Law.

"Permitted Encumbrances" shall mean the following:

(1) liens for taxes, assessments and other governmental charges not delinquent or which are currently being contested in good faith by appropriate proceedings; *provided* that, in the latter case, the specified Person or one of its Subsidiaries shall have set aside on its books adequate reserves with respect thereto;

(2) mechanics' and materialmen's liens not filed of record and similar charges not delinquent or which are filed of record but are being contested in good faith by appropriate proceedings; *provided* that, in the latter case, the specified Person or one of its Subsidiaries shall have set aside on its books adequate reserves with respect thereto;

(3) liens in respect of judgments or awards with respect to which the specified Person or one of its Subsidiaries shall in good faith currently be prosecuting an appeal or other proceeding for review and with respect to which such Person or such Subsidiary shall have secured a stay of execution pending such appeal or such proceeding for review; *provided* that such Person or such Subsidiary shall have set aside on its books adequate reserves with respect thereto;

(4) easements, leases, reservations or other rights of others in, or minor defects and irregularities in title to, property or assets of a specified Person or any of its Subsidiaries; *provided* that such easements, leases, reservations, rights, defects or irregularities do not materially impair the use of such property or assets for the purposes for which they are held; and

(5) any lien or privilege vested in any lessor, licensor or permittor for rent or other obligations of a specified Person or any of its Subsidiaries thereunder so long as the payment of such rent or the performance of such obligations is not delinquent.

"Person" shall mean an individual, partnership, limited liability company, corporation, joint stock company, trust, estate, joint venture, association or unincorporated organization, or any other form of business or professional entity, but shall not include a Governmental Authority.

"Pooling Transaction" shall mean a business combination that qualifies for financial accounting purposes, as a pooling of interests pursuant to Accounting Principles Board Opinion 16 and the interpretations thereof and the Staff Accounting Bulletins of the Commission and the interpretations thereof.

"PSO" shall mean Public Service Company of Oklahoma, an Oklahoma corporation.

"Registration Statement" shall have the meaning ascribed to such term in Section 7.3(a).

"Regulation" shall mean any rule or regulation of any Governmental Authority having the effect of Law.

"Representatives" shall have the meaning ascribed to such term in Section 6.3.

"Reports" shall mean, with respect to a specified Person, all reports, registrations, filings and other documents and instruments required to be filed by the specified Person or any of its Subsidiaries with any Governmental Authority (other than the Commission).

"Required AEP Vote" shall have the meaning ascribed to such term in Section 5.20.

"Required Company Vote" shall have the meaning ascribed to such term in Section 4.20.

"Retention Agreements" shall mean the retention agreements described in Section 6.2(a) of the Company's Disclosure Letter.

"SEC Reports" shall mean (1) all Annual Reports on Form 10-K, (2) all Quarterly Reports on Form 10-Q, (3) all proxy statements relating to meetings of stockholders (whether annual or special), (4) all Current Reports on Form 8-K and (5) all other reports, schedules, registration statements or other documents required to be filed during a specified period by a Person with the Commission pursuant to the Securities Act or the Exchange Act.

"Securities Act" shall mean the Securities Act of 1933, as amended, and the Regulations promulgated thereunder.

"Seeboard" shall mean SEEBOARD plc, a company incorporated in England and a Subsidiary of the Company.

"Share Issuance" shall have the meaning ascribed to such term in Section 5.20.

"Significant Subsidiary" shall mean any subsidiary of the Company or AEP, as the case may be, that would constitute a Significant Subsidiary of such party within the meaning of Rule 1-02 of Regulation S-X of the Commission.

"South Texas Nuclear Facility" shall mean the South Texas nuclear project located in Bay City, Texas.

"State Regulatory Commissions" shall mean: the Public Utility Commission of the State of Texas; the Public Service Commission of the State of Arkansas; the Corporation Commission of the State of Oklahoma; the Public Service Commission of the State of Louisiana; the Indiana Utility Regulatory Commission; the Kentucky Public Service Commission; the Michigan Public Service Commission; the Ohio Public Utility Commission; the Tennessee Regulatory Commission; the Virginia State Corporation Commission; and the West Virginia Public Service Commission.

"State Regulatory Acts" shall mean the utility Laws regulating Domestic Public Utility Companies in the States of Arkansas, Oklahoma, Texas, Louisiana, Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia; in each case, as amended, and the Regulations promulgated thereunder.

A "Subsidiary" of a specified Person shall be any corporation, partnership, limited liability company, joint venture or other legal entity of which the specified Person (either alone or through or together with any other subsidiary) owns, directly or indirectly, over 50% of the stock or other equity or partnership interests the holders of which are generally entitled to vote for the election of the board of directors or other governing body of such corporation or other legal entity.

"Superior Proposal" a *bona fide* written Acquisition Proposal which the Board of Directors of AEP or the Board of Directors of the Company, as the case may be, concludes in good faith (after consultation with its financial advisors and legal counsel), taking into account all legal, financial, regulatory and other aspects of the proposal and the Person making the proposal, (i) would, if consummated, result in a transaction that is more favorable to such party's stockholders, from a strategic and financial point of view, than the transactions contemplated by this Agreement and (ii) is reasonably capable of being completed (*provided* that for purposes of this definition the term Acquisition Proposal shall have the meaning assigned to such term in Section 7.19 except that the reference to "10%" in the definition of "Acquisition Proposal" shall be deemed to be a reference to "50%" and "Acquisition Proposal" shall only be deemed to refer to a transaction involving AEP or the Company, as the case may be, or with respect to assets (including the shares of any Subsidiary of AEP or the Company) of AEP or the Company, as the case may be, and its Subsidiaries, taken as a whole, and not any of its Subsidiaries alone).

"Surviving Corporation" shall mean the Company as the corporation surviving the Merger.

"SWEPCO" shall mean Southwestern Electric Power Company, a Delaware corporation and a Subsidiary of the Company.

"Target Party" shall have the meaning ascribed to such term in Section 9.6(b).

"Task Force" shall have the meaning ascribed to such term in Section 7.18.

"Tax Returns" shall mean all returns, reports or other documents (including information returns) required to be filed by or under any Law with any Governmental Authority with respect to Taxes.

"Taxes" shall mean all taxes, charges, imposts, tariffs, fees, levies or other similar assessments or liabilities, including income taxes, ad valorem taxes, excise taxes, withholding taxes, stamp taxes or other taxes of or with respect to gross receipts, premiums, real property, personal property, windfall profits, sales, use, transfers, licensing, employment, payroll and franchises imposed by or under any Law; and such terms shall include any interest, fines, penalties, assessments or additions to tax resulting from, attributable to or incurred in connection with any such tax or any contest or dispute thereof.

"Terminated AEP Benefit Plans" shall mean Benefit Plans that were sponsored, maintained, or contributed to by AEP or any of its Subsidiaries within six years prior to the date of this Agreement but which have been terminated prior to the date of the Agreement.

"Terminated Company Benefit Plans" shall mean Benefit Plans that were sponsored, maintained, or contributed to by the Company or any of its Subsidiaries within six years prior to the date of this Agreement but which have been terminated prior to the date of the Agreement.

"Terminating AEP Breach" shall have the meaning ascribed to such term in subsection 9.1(c) of the Agreement.

"Terminating Company Breach" shall have the meaning ascribed to such term in subsection 9.1(b) of the Agreement.

"Termination Date" shall have the meaning ascribed to such term in Section 9.1(f).

"Termination Fee" shall have the meaning ascribed to such term in Section 9.6(a).

"Third Party Consents" shall have the meaning ascribed to such term in Section 7.4(d)(i).

"Topping Fee" shall have the meaning ascribed to such term in Section 9.6(b).

"WPC" shall mean Wheeling Power Company, a West Virginia corporation.

"WTU" shall mean West Texas Utilities Company, a Texas corporation and a Subsidiary of the Company.

AFFILIATE'S AGREEMENT

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215-2373

Central and South West Corporation
1616 Woodall Rodgers Freeway
P.O. Box 660164
Dallas, Texas 75266-0164

Ladies and Gentlemen:

The undersigned has been advised that, as of the date hereof, the undersigned may be deemed to be an "affiliate" of Central and South West Corporation, a Delaware corporation (the "Company"), as that term is defined for purposes of paragraphs (c) and (d) of Rule 145 of the Rules and Regulations (the "Rules and Regulations") of the Securities and Exchange Commission (the "SEC") under the Securities Act of 1933, as amended (the "Securities Act").

Pursuant to the terms and subject to the conditions of that certain Agreement and Plan of Merger by and among American Electric Power Company, Inc., a New York corporation ("AEP"), Augusta Acquisition Corporation, a newly formed Delaware corporation and a wholly owned Subsidiary of AEP ("Newco"), and the Company dated as of December 21, 1997 (the "Merger Agreement"), providing for, among other things, the merger of Newco with and into the Company (the "Merger"), the undersigned will be entitled to receive shares of common stock, par value $6.50 per share ("AEP Common Stock"), of AEP in exchange for shares of common stock, par value $3.50 per share ("Company Common Stock"), of the Company owned by me at the effective time of the Merger (the "Effective Time") as determined pursuant to the Merger Agreement.

The undersigned understands that the Merger will be treated for financial accounting purposes as a "pooling of interests" in accordance with generally accepted accounting principles and that the staff of the SEC has issued certain guidelines that should be followed to ensure the application of pooling of interests accounting to the transaction.

In consideration of the agreements contained herein, AEP's and the Company's reliance on this letter in connection with the consummation of the Merger and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the undersigned hereby represents, warrants and agrees that the undersigned has not made and will not make any sale, transfer or other disposition of (i) Company Common Stock or AEP Common Stock within the 30 day period prior to the date of the consummation of the Merger or (ii) AEP Common Stock received by the undersigned pursuant to the Merger or otherwise owned by the undersigned until after such time as financial statements of AEP that include at least 30 days of combined operations of the Company and AEP after the Merger shall have been publicly reported, unless the undersigned shall have delivered to AEP, prior to any such sale, transfer or other disposition, a written opinion from Deloitte & Touche L.L.P., independent public accountants for AEP, or a written no-action letter from the accounting staff of the SEC, in either case in form and substance reasonably satisfactory to AEP, to the effect that such sale, transfer or other disposition will not cause the Merger not to be treated as a "pooling of interests" for financial accounting purposes in accordance with generally accepted accounting principles and the rules, regulations and interpretations of the SEC and (iii) AEP Common Stock received by the undersigned pursuant to the Merger in violation of the Securities Act or the Rules and Regulations. The undersigned has been advised that the offering, sale and delivery of the shares of AEP Common Stock pursuant to the Merger will have been registered with the SEC under the Securities Act on a Registration Statement on Form S-4. The undersigned has also been advised, however, that since the undersigned may be deemed to be an affiliate of the Company at the time the Merger is submitted for a vote of the stockholders of the Company, AEP Common Stock received by the undersigned pursuant to the Merger can be sold by the undersigned only (i) pursuant to an effective registration statement under the Securities Act of 1933 (the "Securities Act"), (ii) in conformity with the volume and other limitations of Rule 145 promulgated by the SEC under the Securities Act, or (iii) in reliance upon an exemption from registration that is available under the Securities Act.

The undersigned also understands that instructions will be given to the transfer agent for AEP Common Stock with respect to AEP Common Stock to be received by the undersigned pursuant to the Merger and that there will be placed on the certificates representing such shares of AEP Common Stock, or any substitutions therefor, a legend stating in substance as follows:

> "These shares were issued in a transaction to which Rule 145 promulgated under the Securities Act of 1933 applies. These shares may only be transferred in accordance with the terms of such Rule and an Affiliate's Agreement between the original holder of such shares and AEP, a copy of which agreement is on file at the principal offices of AEP."

It is understood and agreed that the legend set forth above shall be removed upon surrender of certificates bearing such legend by delivery of substitute certificates without such legend if the undersigned shall have delivered to AEP an opinion of counsel, in form and substance reasonably satisfactory to AEP, to the effect that (i) the sale or disposition of the shares represented by the surrendered certificates may be effected without registration of the offering, sale and delivery of such shares under the Securities Act and (ii) the shares to be so transferred may be publicly offered, sold and delivered by the transferee thereof without compliance with the registration provisions of the Securities Act.

By its execution hereof, AEP agrees that it will, as long as the undersigned owns any AEP Common Stock to be received by the undersigned pursuant to the Merger, take all reasonable efforts to make timely filings with the SEC of all reports required to be filed by it pursuant to the Securities Exchange Act of 1934, as amended, and will promptly furnish upon written request of the undersigned a written statement confirming that such reports have been so timely filed.

If you are in agreement with the foregoing, please so indicate by signing below and returning a copy of this letter to the undersigned, at which time this letter shall become a binding agreement between us.

Very truly yours,

By: ______________________________

Name:
Title:
Date:
Address:

ACCEPTED this day
of , 1998

Attachment 1
Page 209 of 215
KPSC Case No. 99-149
TC (1st Set)
Order Dated April 22, 1999
Item No. 4

AMERICAN ELECTRIC POWER COMPANY, INC.

By: ______________________________

Name:
Title:

CENTRAL AND SOUTH WEST CORPORATION

By: ______________________________

Name:
Title:

AFFILIATE'S AGREEMENT

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215-2373

Central and South West Corporation
1616 Woodall Rodgers Freeway
P.O. Box 660164
Dallas, Texas 75266-0164

Ladies and Gentlemen:

The undersigned has been advised that, as of the date hereof, the undersigned may be deemed to be an "affiliate" of American Electric Power Company, Inc., a New York corporation ("AEP"), as that term is defined in the Rules and Regulations (the "Rules and Regulations") of the Securities and Exchange Commission (the "Commission") under the Securities Act of 1933, as amended (the "Securities Act").

The undertakings contained in this Affiliate's Agreement are being given by the undersigned in connection with that certain Agreement and Plan of Merger by and among AEP, Augusta Acquisition Corporation, a newly formed Delaware corporation and a wholly owned Subsidiary of AEP ("Newco"), and Cypress, a Delaware corporation (the "Company") dated as of December 21, 1997 (the "Merger Agreement"), providing for, among other things, the merger of Newco with and into the Company (the "Merger").

The undersigned understands that the Merger will be treated for financial accounting purposes as a "pooling of interests" in accordance with generally accepted accounting principles and that the staff of the SEC has issued certain guidelines that should be followed to ensure the application of pooling of interests accounting to the transaction.

In consideration of the agreements contained herein, AEP's and the Company's reliance on this letter in connection with the consummation of the Merger and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the undersigned hereby represents, warrants and agrees that the undersigned has not made and will not make any sale, transfer or other disposition of (i) AEP Common Stock or Company Common Stock within the thirty day period prior to the date of the consummation of the Merger or (ii) AEP Common Stock owned by the undersigned until such time as financial statements that include at least 30 days of combined operations of the Company and AEP after the Merger shall have been publicly reported, unless the undersigned shall have delivered to AEP prior to any such sale, transfer or other disposition, a written opinion from Deloitte & Touche L.L.P., independent public accountants for AEP, or a written no-action letter from the accounting staff of the SEC, in either case in form and substance reasonably satisfactory to AEP, to the effect that such sale, transfer or other disposition will not cause the Merger not to be treated as a "pooling of interests" for financial accounting purposes in accordance with generally accepted accounting principles and the rules, regulations and interpretations of the SEC.

If you are in agreement with the foregoing, please so indicate by signing below and returning a copy of this letter to the undersigned, at which time this letter shall become a binding agreement between us.

Very truly yours,

By: ______________________________

Name:
Title:
Date:
Address:

ACCEPTED this day
of , 1998

CENTRAL AND SOUTH WEST
CORPORATION

By: ______________________________

Name:
Title:

AMERICAN ELECTRIC POWER COMPANY,
INC.

By: ______________________________

Name:
Title:

Annex II

SALOMON SMITH BARNEY

212-783-7000

A Member of TravelersGroup

April 16, 1998

Board of Directors
American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, OH 43215-2373
Ladies and Gentlemen:

You have requested our opinion as investment bankers as to the fairness, from a financial point of view, to American Electric Power Company, Inc. (the "Company") of the consideration to be paid by the Company in connection with the proposed merger (the "Proposed Merger") of Augusta Acquisition Corporation ("Mergeco"), a wholly owned subsidiary of the Company, with Central and South West Corporation (the "Subject Company"), pursuant to the Agreement and Plan of Merger (the "Agreement"), dated as of December 21, 1997, by and among the Company, Mergeco and the Subject Company.

As more specifically set forth in the Agreement, and subject to the terms and conditions thereof, Mergeco will merge with and into the Subject Company, and each issued and outstanding share of common stock, par value $3.50 per share, of the Subject Company ("Subject Company Common Stock") (other than shares held in treasury of the Subject Company) will be converted in the Proposed Merger into the right to receive 0.60 of a share of common stock, par value $6.50 per share, of the Company ("Company Common Stock"), subject to adjustment.

As you are aware, Salomon Smith Barney has acted as financial advisor to the Company in connection with the Proposed Merger and will receive a fee for our services, a substantial portion of which is contingent upon consummation of the Proposed Merger. Additionally, Salomon Smith Barney or its affiliates have previously rendered certain investment banking and financial advisory services to the Company and the Subject Company, for which we have received customary compensation. In addition, in the ordinary course of business, we may actively trade the debt and equity securities of the Company and the Subject Company for our own account and for the accounts of customers and, accordingly, may at any time hold a long or short position in such securities.

In connection with rendering our opinion we have reviewed and analyzed, among other things, the following: (i) the Agreement; (ii) certain publicly available information concerning the Company, including the Annual Reports on Form 10-K of the Company for each of the years in the four year period ended December 31, 1997 and the Quarterly Reports on Form 10-Q of the Company for the quarters ended March 31, June 30 and September 30, 1997, respectively; (iii) certain other internal information, primarily financial in nature, including projections, concerning the business and operations of the Company furnished to us by the Company for purposes of our analysis; (iv) certain publicly available information concerning the trading of, and the trading market for, the Company Common Stock; (v) certain publicly available information concerning the Subject Company, including the Annual Reports on Form 10-K of the Subject Company for each of the years in the four year period ended December 31, 1997 and the Quarterly Reports on Form 10-Q of the Subject Company for the quarters ended March 31, June 30 and September 30, 1997, respectively; (vi) certain other internal information, primarily financial in nature, including projections, concerning the business and operations of the Subject Company furnished to us by the Subject Company and the Company for purposes of our analysis; (vii) certain publicly available information concerning the trading of, and the trading market for, the Subject Company Common Stock; (viii) certain internal information concerning the prospects of the combined operations of the Company and the Subject Company furnished to us by the Company for purposes of our analysis; (ix) certain publicly available information with respect to certain other companies that we believe to be comparable to the Subject Company or the Company and the trading markets for certain of such other companies' securities; and (x) certain publicly available information concerning the nature and terms of certain other transactions that we consider relevant to our inquiry. We have also considered such other information, financial studies, analyses, investigations and financial, economic and market criteria that we deemed relevant. We have also met with certain officers and employees of the Subject Company and Company, to discuss the foregoing, as well as other matters we believe relevant to our inquiry.

In our review and analysis and in arriving at our opinion we have assumed and relied upon the accuracy and completeness of all of the financial and other information provided us or publicly available and have neither attempted independently to verify nor assumed responsibility for verifying any of such information. We have not conducted a physical inspection of any of the properties or facilities of the Subject Company or the Company, nor have we made or obtained or assumed any responsibility for making or obtaining any independent evaluations or appraisals of any of such properties or facilities. With respect to projections, we have assumed that they have been reasonably prepared on bases reflecting the best currently available estimates and judgments of the managements of the Subject Company and the Company as to the future financial performance of the Subject Company and the Company and we express no view with respect to such projections or the assumptions on which they were based. We have also assumed that the conditions precedent to the Proposed Merger in the Agreement will be satisfied and the Proposed Merger will be consummated in accordance with the terms of the Agreement.

In conducting our analysis and arriving at our opinion as expressed herein, we have considered such financial and other factors as we have deemed appropriate under the circumstances including, among others, the following: (i) the historical and current financial position and results of operations of the Subject Company and the Company; (ii) the business prospects of the Subject Company and the Company; (iii) the historical and current market for the Company Common Stock, the Subject Company Common Stock and for the equity securities of certain other companies that we believe to be comparable to the Subject Company or the Company; and (iv) the nature and terms of certain other acquisition transactions that we believe to be relevant. We have also taken into account our assessment of general economic, market and financial conditions as well as our experience in connection with similar transactions and securities valuation generally. Our opinion necessarily is based upon conditions as they exist and can be evaluated on the date hereof and we assume no responsibility to update or revise our opinion based upon circumstances or events occurring after the date hereof. Our opinion as expressed below does not constitute an opinion or imply any conclusion as to the likely trading range for the Company Common Stock following consummation of the Proposed Merger. Our opinion is, in any event, limited to the fairness, from a financial point of view, of the consideration to be paid by the Company in the Proposed Merger and does not address the Company's underlying business decision to effect the Proposed Merger or constitute a recommendation of the Proposed Merger to the Company or a recommendation to any holder of Company Common Stock as to how such holder should vote with respect to the Proposed Merger.

This opinion is intended for the benefit and use of the Company (including its management and directors) in considering the transaction to which it relates and may not be used by the Company for any other purpose or reproduced, disseminated, quoted or referred to by the Company at any time, in any manner or for any purpose, without the prior written consent of Salomon Smith Barney, except that this opinion may be reproduced in full in, and references to the opinion and to Salomon Smith Barney and its relationship with the Company (in each case in such form as Salomon Smith Barney shall approve) may be included in, the proxy statement the Company distributes to holders of Company Common Stock in connection with the Proposed Merger and in the registration statement on Form S-4 filed by the Company of which such proxy statement forms a part.

Based upon and subject to the foregoing, we are of the opinion as investment bankers that the consideration to be paid by the Company in the Proposed Merger is fair, from a financial point of view, to the Company.

Very truly yours,

SALOMON SMITH BARNEY

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TC (1st Set)
Order Dated April 22, 1999
Item No. 4

MORGAN STANLEY

MORGAN STANLEY & CO.
INCORPORATED
1585 BROADWAY
NEW YORK, NEW YORK 10036
(212) 761-4000

April 16, 1998

Board of Directors
Central and South West Corporation
1616 Woodall Rodgers Freeway
Dallas, TX 75266-0164

Members of the Board:

We understand that Central and South West Corporation ("CSW" or the "Company"), American Electric Power Company, Inc. ("AEP") and Newco, a wholly owned subsidiary of AEP, ("Newco"), have entered into an Agreement and Plan of Merger dated as of December 21, 1997 (the "Merger Agreement"), which provides, among other things, for the merger (the "Merger") of Newco with and into CSW. Pursuant to the Merger, CSW will become a wholly owned subsidiary of AEP and each outstanding share of common stock, par value $3.50 per share (the "Company Common Stock") of CSW, other than shares held in treasury or held by AEP or any affiliate of AEP or as to which dissenters' rights have been perfected, will be converted into the right to receive 0.60 shares (the "Exchange Ratio") of common stock par value $6.50 per share of AEP (the "AEP Common Stock"). The terms and conditions of the Merger are more fully set forth in the Merger Agreement.

You have asked for our opinion as to whether the Exchange Ratio pursuant to the Merger Agreement is fair from a financial point of view to holders of shares of the Company Common Stock.

For purposes of the opinion set forth herein, we have;

(i) reviewed certain publicly available financial statements and other information of the Company and AEP;

(ii) reviewed certain internal financial statements and other financial and operating data concerning the Company and AEP prepared by their respective managements;

(iii) analyzed certain financial projections prepared by the managements of the Company and AEP, respectively;

(iv) discussed the past and current operations and financial condition and the prospects of the Company and AEP with senior executives of the Company and AEP, respectively;

(v) reviewed the reported prices and trading activity for the Company Common Stock and AEP Common Stock;

(vi) discussed certain regulatory issues relating to the proposed Merger with senior executives of the Company and AEP;

(vii) compared the financial performance of the Company an AEP and the prices and trading activity of the Company Common Stock and AEP Common Stock with that of certain other comparable publicly-traded companies and their securities;

(viii) reviewed the financial terms, to the extent publicly available, of certain comparable merger and acquisition transactions;

(ix) reviewed the pro forma impact of the Merger on AEP's earnings per share, cash flow, consolidated capitalization and financial ratios;