CASE NUMBER:

1999-149

STITES & HARBISON PLLC
ATTORNEYS

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Post Office Box 634
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MAY 15 2006
PUBLIC SERVICE
COMMISSION

Mark R. Overstreet
(502) 209-1219
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May 15, 2006

HAND DELIVERY

Beth O' Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: ***P.S.C. Case No. 99-149***

Dear Ms. O'Donnell:

Please accept for filing the original and four copies of the Supplemental Responses of Kentucky Power Company d/b/a American Electric Power to the Commission's June 14, 1999 Order in the above-referenced case. The Responses are for the year ended December 31, 2005.

By copy of this letter I am providing the parties to the case with a copy of the Supplemental Response. If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

cc: William H. Jones, Jr.
David F. Boehm
Elizabeth E. Blackford

KE057:KE131:10997:3:FRANKFORT

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MAY 1 5 2006

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

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

RESPONSE OF KENTUCKY POWER COMPANY

Reporting Period: Year Ending December 31, 2005

May 15, 2006

1

Kentucky Power Company

REQUEST

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE

Ten copies of AEP's 10-K are attached. The SEC Form U-13-60 has been replaced as FERC Form 60 and ten copies are provided herewith. The SEC Form U5S is no longer required to be filed due to the repeal of the Public Utility Holding Company Act of 1935.

WITNESS: Errol K Wagner

2

Kentucky Power Company

REQUEST

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE

A general description of the nature of inter-company transactions is contained in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1. There have been no changes to the procedures used to price inter-company transactions from those used in the prior year. Unless exempted, inter-company transactions conducted by or with Kentucky Power Company are priced at fully-allocated cost in accordance with Rules 90 and 91 prescribed by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935.

WITNESS: Errol K Wagner

3

Kentucky Power Company

REQUEST

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE

Below is a list of employees transferred from Kentucky Power Company during the twelve months ending December 31, 2005:

Kentucky Power Company Transferees
12 Months Ending 12/31/2005

Company/Name	Effective Date	Job Title - New	Job Title - Old
AEP Service Corp.			
Estepp, Gregory	11/19/2005	Maintenance Welder	Maintenance Welder
Appalachian Power			
Bowen, Gregory	2/12/2005	Line Mechanic-A	Line Mechanic-A
Dotson, Jeffrey L	11/5/2005	Meter Reader	Line Mechanic-D
Ohio Power Company			
Leunissen, David R	12/31/2005	IT Support Tech II	IT Support Tech II

WITNESS: Errol K Wagner

4

Kentucky Power Company

REQUEST

AEP should file on a quarterly** basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	AEP	KPCo	SHARE
Revenues	$12,111	$460	3.8%
Operating/Maintenance Expense	$8,814	$237	2.9%
No. of Employees at 12/31/2005*	19,435	454	2%

*See Response to Item No. 6

WITNESS: Errol K Wagner

5

Kentucky Power Company

REQUEST

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this response shall be filed on an annual basis.

RESPONSE

During the twelve-month period ending December 31, 2005 there were 27 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers and a turbine part. The total dollar value of the assets transferred was $593,256. The smallest dollar value transferred was one meter at a value of $24. The largest dollar value transferred was 419 transformers at a value of $132,504.

WITNESS: Errol K Wagner

9

Kentucky Power Company

REQUEST

AEP should file a quarterly** report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

Below is a chart showing the number of employees of AEP and each subsidiary for the twelve months ending December 31, 2005:

Company	Description	Employee Count
E01	Kingsport Power Company	55
E02	Appalachian Power company	2,408
E03	Kentucky Power Company	454
E04	Indiana Michigan Power Company	2,341
E06	Wheeling Power Company	59
E07	Ohio Power Company	2,220
E10	Columbus Southern Power Co	1,144
E48	River Transportation Div I&MP	288
E54	Conesville Coal Prep Co	34
E61	AEP Service Corporation	5,757
ECC	AEP Texas Central Co	1,160
EEE	CSW Energy, Inc.	21
EEL	AEP Elmwood LLC	134
EMO	AEP MEMCO	482
EPP	Public Service Co of Oklahoma	1,176
ESS	SouthWestern Electric Power Co	1,315
EWW	AEP Texas North Company	387
	TOTAL	19,435

WITNESS: Errol K Wagner

7

Kentucky Power Company

REQUEST

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE

Please see the attached page.

WITNESS: Errol K Wagner

Kentucky Power Transferees - 12 months ending 12/31/2005

Company/Name	Eff Date	Total Years of Service	Annual Salary
AEP Service Corporation			
Estepp,Gregory	11/19/2005	22	$57,740.80
Appalachian Power Company			
Bowen,Gregory	2/12/2005	19	$53,976.00
Dotson,Jeffrey L	11/5/2005	4	$30,097.60
Ohio Power Company			
Leunissen,David R	12/31/2005	6	$59,931.00

8

Kentucky Power Company

REQUEST

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE

The cost allocation factors used by Kentucky Power Company and other AEP System companies are described in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2. AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky commission in memo form on January 30, 2001 (Case No. 99-149).

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

Kentucky Power Company did not perform any cost allocation studies during the twelve months ending December 31, 2005. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE

The methods used to update or revise the cost allocation factors used by Kentucky Power Company and other AEP System companies were not significantly changed during the year ended December 31, 2005. Allocation factors are revised periodically each year (e.g., monthly, quarterly, semi-annually and annually) based on the most current statistics available for each factor. The allocation factors in use are documented in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2.

AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky Commission in memo form on January 30, 2001. (Case No. 99-149).

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP.[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE

Please see the Company's response to Item No. 11 filed December 8, 2000, which provided a list of AEP's subsidiaries describing the functions and business of each subsidiary.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business.
[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE

Please see response to Item No. 11.

WITNESS: Errol K Wagner

13

Kentucky Power Company

REQUEST

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE

There were no changes during the period ending December 31, 2005 to the terms and conditions of the settlements in any jurisdiction that would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nation clause.

WITNESS: Errol K Wagner

14

Kentucky Power Company

REQUEST

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein.[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE

Please see the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K Wagner

15

Kentucky Power Company

REQUEST

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2005. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE

The overall Customer Average Interruption Duration Index (CAIDI) for Kentucky Power Company (KYPCo) customers during calendar year 2005 was 2.66 hours per customer interrupted. The overall System Average Interruption Frequency Index (SAIFI) for KPCo customers during calendar year 2005 was 2.58 interruptions per customer served.

No Major events were declared for the calendar year of 2005.

KPCo has previously reported on its changes in outage reporting systems. Making comparisons to the 1995-1998 values is very difficult because of the numerous advancements in outage recording technology. The ultimate results are more accurate outage customer count and outage duration values.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2005. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE

Kentucky Customer Calls had an Average Speed of Answer (ASA) of 45 seconds, an Abandonment Rate of 5.90% and a Call Blockage factor of 0.52% for the calendar year of 2005.

WITNESS: Errol K Wagner

17

Kentucky Power Company

REQUEST

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2005.[Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE

In calendar year 2005, Kentucky Power continued to perform circuit inspections, tree trimming, lightning arrester replacement, animal guarding, and pole and cross arm replacements as needed. Kentucky Power provides the following statistics for work in its service territory in 2005: There are a total of 209 distribution circuits in Kentucky. Eighty-two (82) complete circuits were inspected in 2005. The remaining 127 circuits are scheduled for inspections in 2006. Inspected 4,249 wood poles as part of the ground-line treatment program. Poles were replaced or refurbished as necessary. (Also, inspected the condition of 671 metal poles.)

Completed right-of-way maintenance work on 1,711 miles of distribution line. AEP continues its asset management programs to review the performance of its facilities and to make prudent improvements to continue providing reliable and cost-effective electric service to its Kentucky customers.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impact of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE

Kentucky Power continues to compile outage data detailing each circuit's reliability performance. Worst performing circuits are identified considering CAIDI, SAIFI, and repeat outages, as well as those with outage causes than can be addressed through existing asset improvement programs targeting animal, lightning, small conductor failures, and tree cause outages. This allows for the identification of areas needing reliability improvements and for the development of work plans to optimize system performance where within utility control.

Work plans are developed by combining reliability performance with input from field personnel to identify areas that do not satisfy ranking criteria alone. Work plans include ground line treatment of poles; improved fault isolation by installing additional sectionalizing devices; recloser maintenance; and system improvements required due to facility loading, voltage control, and reliability performance.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE

The Company has maintained a high quality workforce which met the customers needs in providing electrical service.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary (ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE

Kentucky Power Company's Regulatory Services Director, Mr. Errol K. Wagner, is the contact designee for the Kentucky Public Service Commissioners and Staff and the Kentucky Attorney General's Office regarding affiliate transactions and personnel transfers.

WITNESS: Errol K Wagner

21

Kentucky Power Company

REQUEST

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE

The Company would prefer customers to initially call the Customer Solution Center (CSC) toll-free telephone number. The representatives of the CSC are capable of answering questions concerning service, reliability concerns and billing issues. However, Kentucky Power's Regulatory Services Department staff, specifically the Regulatory Services Director, is also capable of dealing with billing, maintenance and service reliability issues.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE

Kentucky Power Company's Regulatory Services Director, Mr. Errol K. Wagner, and the Regulatory Services Department staff are the designated employees to work with the Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE

The Company has maintained a sufficient management team in Kentucky to ensure that safe, reliable and efficient electric service is provided and the Company has responded to the needs and inquiries of its customers.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger.
[Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE

Kentucky Power Company continues to adhere to all applicable affiliate standards. In light of the General Assembly's enactment of HB 897 (KRS 278.2201 et seq.) in 2000, and the express terms of the Merger Settlement Agreement and the Order approving the agreement, the affiliate standards and requirements contained in the Merger Settlement Agreement have been superseded by statute. *See, Order, Joint Application of Kentucky Power Company, American Electric Power Company, Inc., and Central and South West Corporation Regarding a Proposed Merger, P.S.C. Case No. 99-149 at page 8 (affiliate standards and guidelines set out in Merger Settlement Agreement to remain in effect "until new affiliate standards imposed by either the Commission or by the General Assembly.")* Accordingly, Kentucky Power Company will not be conducting a biennial audit of affiliated transactions as contemplated by the now superseded standards.

WITNESS: Errol K Wagner

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

RECEIVED
MAY 1 5 2006
PUBLIC SERVICE COMMISSION

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Indicate by check mark if the registrant with respect to American Electric Power Company, Inc., is a well-known seasoned issuer, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrant with respect to AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrant with respect to American Electric Power Company, Inc., is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No. ☒

Indicate by check mark if the registrant with respect to AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No. ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No. ☐

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No. ☐

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company or Ohio Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements of Appalachian Power Company or Ohio Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, or non-accelerated filers. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No. ☒

AEP Generating Company, AEP Texas North Company, Columbus Southern Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
AEP Generating Company	None	
AEP Texas Central Company	None	
AEP Texas North Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	6% Senior Notes, Series D, Due 2032	New York Stock Exchange
Kentucky Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP	American Electric Power Company, Inc.
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPSC or Service Corporation	American Electric Power Service Corporation, a service subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries
AEP Utilities	AEP Utilities, Inc., subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, an electric utility subsidiary of AEP
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
Cardinal Station	Generating facility co-owned by Buckeye and OPCo
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company
Cook Plant	The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation
DOE	United States Department of Energy
Dow	The Dow Chemical Company, and its affiliates collectively, unaffiliated companies
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
East zone public utility subsidiaries	APCo, CSPCo, I&M, KPCo and OPCo
EMF	Electric and Magnetic Fields
ENEC	Expanded net energy clause
EPA	United States Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
FPA	Federal Power Act
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
I&M Power Agreement	Unit Power Agreement Between AEGCo and I&M, dated March 31, 1982
Interconnection Agreement	Agreement, dated July 6, 1951, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KPCo	Kentucky Power Company, a public utility subsidiary of AEP
LLWPA	Low-Level Waste Policy Act of 1980

TABLE OF CONTENTS

Documents Incorporated By Reference

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2005: AEP Generating Company AEP Texas Central Company AEP Texas North Company American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2006 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2005	Part III
Portions of Information Statements of the following companies for 2006 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2005: Appalachian Power Company Ohio Power Company	Part III

This combined Form 10-K is separately filed by AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
AEP Generating Company	None
AEP Texas Central Company	4.00% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.20% Cumulative Preferred Stock, Non-Voting, $100 par value
AEP Texas North Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	4.125% Cumulative Preferred Stock, Non-Voting, $100 par value
Kentucky Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.65% Cumulative Preferred Stock, Non-Voting, $100 par value
	5.00% Cumulative Preferred Stock, Non-Voting, $100 par value

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2005, the last trading date of the registrants' most recently completed second fiscal quarter	Number of shares of common stock outstanding of the registrants at December 31, 2005
AEP Generating Company	None	1,000 ($1,000 par value)
AEP Texas Central Company	None	2,211,678 ($25 par value)
AEP Texas North Company	None	5,488,560 ($25 par value)
American Electric Power Company, Inc.	$14,172,701,867	393,718,838 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns, directly or indirectly, all of the common stock of AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Abbreviation or Acronym	Definition
LPSC	Louisiana Public Service Commission
MECPL	Mutual Energy CPL, L.P., a Texas REP and former AEP affiliate
MEWTU	Mutual Energy WTU, L.P., a Texas REP and former AEP affiliate
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
Nox	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 43.47% equity interest
PJM	PJM Interconnection, L.L.C., a regional transmission organization
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PUCO	The Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935, as amended (repealed effective February 8, 2006)
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (1,300 MW, coal-fired) located near Rockport, Indiana
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
STP	South Texas Project Nuclear Generating Plant, of which TCC owned 25.2%
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TCA	Transmission Coordination Agreement dated January 1, 1997 by and among, PSO, SWEPCo, TCC, TNC and AEPSC, which allocates costs and benefits in connection with the operation of the transmission assets of the four public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
TEA	Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
Tractebel	Tractebel Energy Marketing, Inc.
TVA	Tennessee Valley Authority
VSCC	Virginia State Corporation Commission

Abbreviation or Acronym	Definition
West zone public utility subsidiaries	PSO, SWEPCo, TCC and TNC
WPCo	Wheeling Power Company
WVPSC	West Virginia Public Service Commission

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its registrant subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its registrant subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of and transportation for fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including implementation of EPACT and membership in and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

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 that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio, Texas and Virginia has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system and, as a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The member companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

At December 31, 2005, the subsidiaries of AEP had a total of 19,630 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 942,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 581,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2005, I&M had 2,633 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 46,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. At December 31, 2005, Kingsport Power Company had 55 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2005, OPCo had 2,220 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 514,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, PSO had 1,176 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 450,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, SWEPCo had 1,498 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. Among the principal industries served by TCC are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. Among the principal industries served by TNC are agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2005, WPCo had 59 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2005, AEPSC had 5,760 employees.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2005 are as follows:

Description	AEP System(a)	APCo	CSPCo	I&M	KPCo
	(in thousands)				
UTILITY OPERATIONS:					
Retail Sales					
Residential Sales	$3,486,000	$668,259	$555,487	$396,739	$143,606
Commercial Sales	2,468,000	334,511	495,771	301,998	83,261
Industrial Sales	2,211,000	363,441	127,819	345,853	127,676
Total Other Retail Sales	240,000	62,586	15,671	17,431	5,460
Total Retail	8,405,000	1,428,797	1,194,748	1,062,021	360,003
Wholesale					
Off-System Sales	1,905,000	309,456	160,783	324,280	73,970
Transmission	408,000	70,337	38,439	41,099	16,663
Total Wholesale	2,313,000	379,793	199,222	365,379	90,633
Other Electric Revenues	260,000	36,580	19,086	18,466	8,222
Other Operating Revenues	186,000	8,770	4,865	33,985	1,682
Sales To Affiliates	-	322,333	124,411	412,751	70,803
Gross Utility Operating Revenues	11,164,000	2,176,273	1,542,332	1,892,602	531,343
Provision For Rate Refund	29,000	-	-	-	-
Utility Operating Revenues, Net	11,193,000	2,176,273	1,542,332	1,892,602	531,343
Investments – Gas Operations	463,000	-	-	-	-
Investments – Other	455,000	-	-	-	-
TOTAL REVENUES	$12,111,000	$2,176,273	$1,542,332	$1,892,602	$531,343

Description	OPCo	PSO	SWEPCo	TCC(b)	TNC(b)
	(in thousands)				
UTILITY OPERATIONS:					
Retail Sales					
Residential Sales	$503,833	$453,572	$408,269	$231,266	$57,449
Commercial Sales	324,925	310,495	337,773	171,128	28,538
Industrial Sales	560,883	301,778	263,772	35,800	8,106
Total Other Retail Sales	23,469	87,160	6,892	9,327	11,221
Total Retail	1,413,110	1,153,005	1,016,706	447,521	105,314
Wholesale					
Off-System Sales	388,138	77,403	230,646	134,710	218,959
Transmission	53,554	20,345	36,765	89,769	40,851
Total Wholesale	441,692	97,748	267,411	224,479	259,810
Other Electric Revenues	67,478	10,671	55,532	24,310	5,684
Other Operating Revenues	30,417	2,976	1,089	48,458	41,770
Sales to Affiliates	681,852	39,678	65,408	14,973	47,164
Gross Utility Operating Revenues	2,634,549	1,304,078	1,406,146	759,741	459,742
Provision for Rate Refund	-	-	(767)	33,505	(854)
Utility Operating Revenues, Net	2,634,549	1,304,078	1,405,379	793,246	458,888
Investments – Gas Operations	-	-	-	-	-
Investments – Other	-	-	-	-	-
TOTAL REVENUES	$2,634,549	$1,304,078	$1,405,379	$793,246	$458,888

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated, including $270,545,000 of AEGCo's revenues for the year ended December 31, 2005, which resulted from its wholesale business, including its marketing and trading of power.

(b) TCC and TNC revenues from distribution and transmission services to REPs are reflected in retail classes of customer.

EPACT AND THE REPEAL OF PUHCA

EPACT was signed into law on August 8, 2005. Among other things, EPACT repealed PUHCA, effective February 8, 2006. PUHCA regulated many significant aspects of a registered holding company system, such as the AEP System. PUHCA limited the operations of a registered holding company system to a single integrated public utility system and such other businesses as were incidental or necessary to the operations of the system. PUHCA also required that transactions between associated companies in a registered holding company system be performed at cost, with limited exceptions. As a result of PUHCA's repeal, utility holding companies, including the AEP system, are no longer limited to a single integrated public utility system. Further, utility holding companies are no longer restricted from acquiring businesses that may not be related to the utility business. Jurisdiction over certain holding company related activities has been transferred to the FERC. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators will be permitted to review the books and records of any company within a holding company system.

EPACT contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry, incentives for emissions reductions and federal insurance and incentives to build new nuclear power plants. It gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases. The law required the FERC to issue certain regulations implementing EPACT within 120 days of enactment. We have reviewed the proposed rules and are participating in the public comment process. However, we cannot currently predict what impact the final rules will have on our financial condition and results of operations.

AEP-CSW MERGER

On June 15, 2000, a wholly owned merger subsidiary of AEP merged with and into CSW (now known as AEP Utilities, Inc.). As a result, CSW became a wholly owned subsidiary of AEP. The four wholly owned public utility subsidiaries of CSW - PSO, SWEPCo, TCC and TNC - became indirect wholly owned public utility subsidiaries of AEP as a result of the merger. The merger was approved by the FERC and the SEC.

On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to properly explain how the merger met the requirements of PUHCA and remanded the case to the SEC for further review. Upon PUHCA's repeal in February 2006, we received a letter from the SEC which formally dismissed the proceeding challenging our merger.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt is also used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2005, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2005 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as leasing arrangements, including the leasing of utility assets and coal mining and transportation equipment and facilities.

Credit Ratings

In September 2005, Moody's upgraded AEP's senior unsecured rating to Baa2 from Baa3 and its commercial paper rating to Prime-2 from Prime-3. There were no changes in the ratings or rating outlook for AEP's rated subsidiaries in 2005. S&P and Fitch did not change the ratings of AEP or its rated subsidiaries during 2005.

See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2005 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants other than AEGCo.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP's subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that are potentially material to the AEP system include:

- The CAA and CAAA and state laws and regulations (including State Implementation Plans) that require compliance, obtaining permits and reporting as to air emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments*.

- Litigation with the federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating plants required additional permitting or pollution control technology, and/or whether emissions from coal-fired generating plants cause or contribute to global climate changes. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters - Environmental Litigation* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2005 Annual Reports, for further information.

- Rules issued by the EPA and certain states that require substantial reductions in SO_2, mercury and NOx emissions, some of which became effective in 2005. The remaining compliance dates and proposals would take effect periodically through as late as 2018. AEP is installing (and has installed) emission control technology and is taking other measures to comply with required reductions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments* included in the 2005 Annual Reports for further information.

- CERCLA, which imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. AEP does not, however, anticipate that any of its currently identified CERCLA-related issues will result in material costs or penalties to the AEP System. See *Note 7*, included in the 2005 Annual Reports, under the heading entitled *The*

Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation for further information.

- The Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits. In July 2004, the EPA adopted a new Clean Water Act rule to reduce the number of fish and other aquatic organisms killed at once-through cooled power plants. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2005 Annual Reports, under the heading entitled *Environmental Matters - Clean Water Act Regulations* for additional information.

- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain wastes. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion byproducts, which the EPA has determined are not hazardous waste subject to RCRA.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters*, included in the 2005 Annual Reports, for further information with respect to environmental issues.

If our expenditures for pollution control technologies, replacement generation and associated operating costs are not recoverable from customers through regulated rates (in regulated jurisdictions) or market prices (in deregulated jurisdictions), those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System.

See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies,* included in the 2005 Annual Reports, for further information with respect to environmental matters.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2004 and 2005 and the current estimates for 2006, 2007 and 2008 are shown below, in each case excluding AFUDC. Substantial investments in addition to the amounts set forth below are expected by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted. Future investments could be significantly greater if litigation regarding whether AEP properly installed emission control equipment on its plants is resolved against any AEP subsidiaries or emissions reduction requirements are accelerated or otherwise become more onerous. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies,* included in the 2005 Annual Reports, for more information regarding this litigation and environmental expenditures in general.

Historical and Projected Environmental Investments

	2004 Actual	2005 Actual	2006 Estimate	2007 Estimate	2008 Estimate
			(in thousands)		
AEGCo	$6,500	$1,400	$2,400	$1,300	$11,700
APCo	159,100	231,200	537,200	291,800	198,000
CSPCo	23,200	32,200	152,200	112,500	43,000
I&M	11,800	62,900	22,200	8,600	13,500
KPCo	2,700	13,100	54,800	68,900	67,800
OPCo	133,000	458,600	735,300	513,000	72,700
PSO	100	200	300	1,200	0
SWEPCo	4,000	11,900	26,600	20,700	13,100
TCC	0	0	0	0	0
TNC	0	(100)	300	100	0
AEP System	$340,400	$811,400	$1,531,300	$1,018,100	$419,800

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP's business operations. Utility operations include (i) the generation, transmission and distribution of electric power to retail customers and (ii) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

AEP's public utility subsidiaries own or lease approximately 35,000 MW of domestic generation. See *Item 2 — Properties* for more information regarding AEP's generation capacity.

AEP Power Pool and CSW Operating Agreement

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio." The Interconnection Agreement has been approved by the FERC.

The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone public utility subsidiaries. As of December 31, 2005, the member-load-ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	7,080	31.2
CSPCo	4,105	18.1
I&M	4,193	18.5
KPCo	1,685	7.4
OPCo	5,638	24.8

The Ohio Act was enacted in 2001. To comply with that law CSPCo and OPCo functionally separated their generation business from their remaining operations. They plan to remain functionally separated through at least December 31, 2008 as authorized by their rate stabilization plan approved by the PUCO. See *Management's Financial Discussion and Analysis of Results of Operations,* under the heading entitled *Ohio Regulatory Activity* included in the 2005 Annual Reports under the heading entitled *Significant Factors* and Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring*, included in the 2005 Annual Reports, for more information.

Since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which provides, among other things, for the transfer of emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement and the Allowance Agreement during the years ended December 31, 2003, 2004 and 2005:

	2003	2004	2005
	(in thousands)		
APCo	$218,000	$239,400	$288,000
CSPCo	276,800	284,900	285,600
I&M	(118,800)	(141,500)	(197,400)
KPCo	38,400	31,600	42,200
OPCo	(414,400)	(414,400)	(418,400)

PSO, SWEPCo, TCC, TNC, and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the west zone public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP west zone public utility subsidiaries as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. The separation of the generation business undertaken by TCC and TNC to comply with the Texas Act has made the business operations of TCC and TNC incompatible with the CSW Operating Agreement. We have applied with the FERC to remove these two companies from the CSW Operating Agreement. Upon approval (or earlier for TCC, if the sale of its interest in the Oklaunion plant occurs first), these companies will no longer supply generating capacity under the CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2003, 2004 and 2005:

	2003	**2004**	**2005**
		(in thousands)	
PSO	$44,000	$55,000	$27,600
SWEPCo	(46,600)	(59,800)	(27,500)
TCC	(29,500)	1,100	0
TNC	32,100	3,700	(100)

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, to REPs) by such public utility subsidiary at rates approved (other than in the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions continue to transition to the use of market rates for generation. See *Regulation — Rates* under *Item 1, Utility Operations.*

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See *Risk Management and Trading*, below, for a discussion of the trading and marketing of such power.

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's east and west zone operating subsidiaries. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits for activities within each zone. The separation of the generation business undertaken by TCC and TNC to comply with the Texas Act has made the business operations of TCC and TNC incompatible with the System Integration Agreement. As a result, we have applied with the FERC to remove these two companies from this agreement.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2005, counterparties and exchanges have posted approximately $324 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $127 million with counterparties and exchanges). Since open trading contracts are valued based on changes in market power prices, exposures change daily.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	2003	**2004**	**2005**
Coal and Lignite	80%	83%	83%
Natural Gas	7%	5%	6%
Nuclear	9%	12%	10%
Hydroelectric and other	4%	1%	1%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages and to the sale of TCC's share of STP in May 2005. Variations in the generation of natural gas power are primarily related to the availability of cheaper alternatives to fulfill certain power requirements and the deactivation or sale of certain gas-fired plants owned by TCC and TNC. Price increases in one or more fuel sources relative to other fuels generally result in increased use of other fuels.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations, short-term, and spot agreements with various producers and coal trading firms. The price for coal fuels increased in 2005 and we expect that this trend may continue. Management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with products from different coal regions and sources of differing heat and sulfur contents. This rebalancing is an ongoing process that is expected to continue. Management believes, but cannot provide assurances, that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. See *Item 1 - Investments-Other* for a discussion of AEP's coal marketing and transportation operations.

The following table shows the amount of coal and lignite delivered to the AEP System during the past three years and the average delivered price of spot coal purchased by System companies:

	2003	**2004**	**2005**
Total coal delivered to AEP operated plants (thousands of tons)	76,042	71,778	75,063
Average price per ton of spot-purchased coal	$28.91	$33.83	$43.75

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor issues and weather conditions that may interrupt deliveries. At December 31, 2005, the System's coal inventory was approximately 30 days of normal usage.

In cases of emergency or shortage, system companies have developed programs to conserve coal supplies at their plants. Such programs have been filed and reviewed with officials of federal and state agencies and, in some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to ratemaking principles by which such electric utilities would be compensated.

In addition, the federal government is authorized, under prescribed conditions, to reallocate coal and to require the transportation thereof, for the use at power plants or major fuel-burning installations experiencing fuel shortages.

Natural Gas: Through its public utility subsidiaries, AEP consumed over 109 billion cubic feet of natural gas during 2005 for generating power. A majority of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of long-term, monthly and seasonal firm purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant.

Nuclear: I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review, evaluate and fulfill I&M's requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M anticipates that the Cook Plant has sufficient storage capacity for its spent nuclear fuel to permit normal operations through 2013. I&M has initiated a project to study the use of dry cask storage.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected;
- Escalation of various cost elements (including, but not limited to, general inflation);
- Further development of regulatory requirements governing decommissioning;
- Limited availability to date of significant experience in decommissioning such facilities;
- Technology available at the time of decommissioning differing significantly from that assumed in studies;
- Availability of nuclear waste disposal facilities; and
- Availability of a DOE facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections.

See Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2005 Annual Reports, for information with respect to nuclear waste and decommissioning and related litigation.

Low-Level Radioactive Waste: The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available, but South Carolina and Utah operate low-level radioactive waste disposal sites and currently accept low-level radioactive waste from Michigan. I&M's access to the South Carolina facility is currently allowed through the end of fiscal year 2008. There is currently no set date limiting I&M's access to the Utah facility.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC and called the Mone Plant. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2006. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

AEGCo: Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in Unit 1 of the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KPCo pursuant to unit power agreements, which have been approved by the FERC.

The I&M Power Agreement provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M). When added to amounts received by AEGCo from any other sources, such amounts will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires in December 2022.

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities; (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant; (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements); and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The capital funds agreement will terminate after all AEGCo obligations have been paid in full.

OVEC: AEP, CSPCo and several unaffiliated utility companies jointly own OVEC. In April 2004, AEP agreed to sell a portion of its shares in OVEC (.73% of OVEC) to Louisville Gas and Electric Company. The sale was completed in the first quarter of 2005. As a result of the sale, the aggregate equity participation of AEP and CSPCo in OVEC decreased from 44.2% to 43.47%. Until September 1, 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are now entitled to receive and obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 42.1%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2006. An Amended and Restated ICPA has been unanimously approved and executed by the sponsoring companies and OVEC. The amended agreement, filed with and accepted by FERC, extends the term of the ICPA for an additional 20 years to March 13, 2026. The aggregate power participation ratio of the AEP entities in the Amended and Restated ICPA is 43.47%. The AEP-affiliated owners of OVEC and the other owners are evaluating the need for environmental investments related to their ownership interests, which may be material.

Buckeye: On October 1, 2004, AEP joined PJM, and the Buckeye transmission service over the AEP System was transferred under the PJM OATT. Buckeye is entitled under the Cardinal Station Agreement to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on July 25, 2005, was recorded at 1,434,807 kilowatts.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEP's public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See *Item 2—Properties* for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates established and approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *Regulation—Rates*. The FERC regulates and approves the rates for wholesale transmission transactions. See *Item 1 – Business/Utility Operations - Regulation—FERC.* As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see *Item 1 – Business/Utility Operations - Competition.*

AEP Transmission Pool

Transmission Equalization Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system and are parties to the Transmission Equalization Agreement, dated April 1, 1984, as amended (TEA), defining how they share the costs and benefits associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345kV and above) and certain facilities operated at lower voltages (138kV up to 345kV). The TEA has been approved by the FERC. Sharing under the TEA is based upon each company's "member-load-ratio." The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. As of December 31, 2005, the member-load-ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	7,080	31.2
CSPCo	4,105	18.1
I&M	4,193	18.5
KPCo	1,685	7.4
OPCo	5,638	24.8

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2003, 2004 and 2005:

	2003	2004	2005
		(in thousands)	
APCo	$0	$(500)	$8,900
CSPCo	38,200	37,700	34,600
I&M	(39,800)	(40,800)	(47,000)
KPCo	(5,600)	(6,100)	(3,500)
OPCo	7,200	9,700	7,000

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone public utility subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone public utility subsidiaries have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the AEP OATT on their behalf. The TCA also provides for the allocation among the west zone public utility subsidiaries of revenues collected for transmission and ancillary services provided under the AEP OATT.

The following table shows the net (credits) or charges allocated among the parties to the TCA during the years ended December 31, 2003, 2004 and 2005:

	2003	2004	2005
		(in thousands)	
PSO	$4,200	$8,100	$3,500
SWEPCo	5,000	13,800	5,200
TCC	(3,600)	(12,200)	(3,800)
TNC	(5,600)	(9,700)	(4,900)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See *Item 1 – Business/Utility operations - Regional Transmission Organizations,* below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone public utility subsidiaries. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TEA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The System Transmission Integration Agreement contemplates that additional service schedules may be added as circumstances warrant.

Regional Transmission Organizations

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

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. As a condition of FERC's approval in 2000 of AEP's merger with CSW, AEP was required to transfer functional control of its transmission facilities to one or more RTOs. The AEP East Companies integrated into PJM (a FERC-approved RTO) on October 1, 2004.

SWEPCo and PSO are members of the SPP. In February 2004, the FERC conditionally approved SPP as an RTO. In October 2004, the FERC issued an order granting RTO status to SPP subject to certain filings. The Arkansas Public Service Commission and LPSC are concerned about the effect on retail ratepayers of utilities in Louisiana and Arkansas joining RTOs. These commissions have ordered the utilities in those states, including our utilities, to analyze and submit to them the costs and benefits of RTO options available to the utilities. Certain states in the region have undertaken and released a study investigating the costs and benefits of SPP developing into a RTO that administers energy and associated markets.

The remaining west zone public utility subsidiaries (TCC and TNC) are members of ERCOT.

See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2005 Annual Reports under the heading entitled *RTO Formation/Integration Costs* and *Transmission Rate Proceedings at the FERC* for a discussion of public utility subsidiary participation in RTOs.

REGULATION

General

Except for retail generation sales in Ohio, Virginia and the ERCOT area of Texas, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional regulation by the state utility commissions. While still regulated, retail sales in Michigan are now made at unbundled rates. See *Item 1 – Utility Operations - Electric*

Restructuring and Customer Choice Legislation and *Rates,* below. AEP's subsidiaries are also subject to regulation by the FERC under the FPA. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry, incentives for emissions reductions and federal insurance and incentives to build new nuclear power plants. It gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (i) a utility's revenues and expenses during a defined test period and (ii) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time as part of a transition to customer choice of generation suppliers, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

The rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In Ohio, Virginia and the ERCOT area of Texas, rates are transitioning from bundled cost-based rates for electric service to unbundled cost-based rates for transmission and distribution service on the one hand, and market pricing for and/or customer choice of generation on the other. In Ohio, the PUCO has approved the rate stabilization plans filed by OPCo and CSPCo which, among other things, address retail generation service rates through December 31, 2008. In Virginia, APCo's base rates are currently capped, subject to certain adjustments described below, at their mid-1999 levels until December 31, 2010, or sooner if the VSCC finds that a competitive market for generation exists in Virginia.

Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes. While the historical framework remains in a portion of AEP's service territory, recovery of increased fuel costs through a fuel adjustment clause is no longer provided for in Ohio. We are seeking to reactivate fuel clause mechanisms in West Virginia and have received approval from the WVPSC to begin deferral accounting associated with the fuel clause mechanism effective July 1, 2006. Fuel recovery is also limited in the ERCOT area of Texas, but because we mainly serve customers through unaffiliated REPs, there is little impact on AEP of fuel recovery procedures related to service in ERCOT.

The following state-by-state analysis summarizes the regulatory environment of each jurisdiction in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction.

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, I&M's base rates are capped through June 30, 2007. Its fuel recovery rate is capped through that time period at a level that automatically increased in January 2006 and will do so again in January 2007. I&M expects, however, that its actual fuel costs will exceed the capped fuel rates permitted through June 30, 2007. See Note 4 to the consolidated financial statements, entitled *Rate Matters – I&M Indiana Settlement Agreement,* included in the 2005 Annual Reports, for more information.

Ohio: CSPCo and OPCo each operated as a functionally separated utility and provided "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2005. The PUCO approved the rate stabilization plan filed by CSPCo and OPCo (which, among other things, addresses default retail generation service rates from January 1, 2006 through December 31, 2008). The Ohio Consumers' Counsel has appealed the PUCO's approval of the rate stabilization plans. Retail generation rates will be determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are providing and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates will be frozen (with certain exceptions, including automatic annual increases in generation rates of 3% and 7% for CSPCo and OPCo, respectively) from their levels as of December 31, 2005 through December 31, 2008. Transmission services will continue to be provided at rates established by the FERC. See Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring*, included in the 2005 Annual Reports, for more information.

Oklahoma: PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2005 Annual Reports, for information regarding current rate proceedings.

Texas: TCC has sold substantially all of its generation assets and TNC currently operates on a functionally separated basis. TCC and TNC serve most of their retail customers in the ERCOT area of Texas through non-affiliated REPs. TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. See Notes 4 and 6 to the consolidated financial statements, entitled *Rate Matters* and *Customer Choice and Industry Restructuring*, respectively, included in the 2005 Annual Reports, for information on current rate proceedings and TCC's true-up proceedings.

In May 2003, the PUCT delayed competition in the SPP area of Texas until at least January 1, 2007. As such, SWEPCo's Texas operations continue to operate and to be regulated as a traditional bundled utility with both base and fuel rates.

Virginia: APCo provides retail electric service in Virginia at unbundled rates. APCo's unbundled generation, transmission (which reflect FERC approved transmission rates) and distribution rates as well as its functional separation plan were approved by the VSCC in December 2001. APCO's base rates are capped at their mid-1999 levels until the end of the transition period (now December 31, 2010), or sooner if the VSCC finds that a competitive market for generation exists in Virginia. APCo is permitted to seek two changes to its capped rates through December 31, 2010. In addition, APCo is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution reliability and compliance with state or federal environmental laws or regulations. APCo is entitled to adjustments to fuel rates through 2010 to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. APCo recovers its generation capacity charges through capped base rates. In July 2005, APCo filed a request with the VSCC seeking approval to recover additional environmental and reliability-related costs. The request is currently pending before the VSCC. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2005 Annual Reports, for additional information on current rate proceedings.

West Virginia: APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC. While West Virginia generally allows for timely recovery of fuel costs, an earlier rate proceeding for both APCo and WPCo resulted in the suspension of their operative fuel clause mechanisms (though they continue to recover a fixed level of fuel costs through bundled rates). In August 2005, APCo and WPCo collectively filed an application with the WVPSC seeking an increase in their retail rates and the reactivation of their suspended operative fuel clause and other recovery mechanisms. That matter is currently pending before the WVPSC. We have received approval from the WVPSC to begin deferral accounting associated with the fuel clause mechanism effective July 1, 2006. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2005 Annual Reports, for additional information on current rate proceedings.

Other Jurisdictions: The public utility subsidiaries of AEP also provide service at regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan.

The following table illustrates the current rate regulation status of the states in which the public utility subsidiaries of AEP operate:

	Status of Base Rates for		Fuel Clause Rates(7)		
Jurisdiction	**Power Supply**	**Energy Delivery**	**Status**	**Off-System Sales Profits Shared with Ratepayers**	**Percentage of AEP System Retail Revenues(1)**
Ohio	See footnote 2	Distribution frozen through 2008(2)	None	Not applicable	31%
Oklahoma	Frozen through April 2006	Frozen through April 2006	Active	Yes	14%
Texas ERCOT	See footnote 3	Not capped or frozen	Not applicable	Not applicable	7%(3)
Texas SPP	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	5%(3)
Indiana	Capped until 6/30/07	Capped until 6/30/07	Capped until 6/30/07 (4)	No	11%
Virginia	Capped until as late as 12/31/10(5)	Capped until as late as 12/31/10(5)	Active	No	9%
West Virginia	Not capped or frozen	Not capped or frozen	Suspended (6)	Yes, but suspended (6)	9%
Louisiana	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%
Kentucky	Not capped or frozen	Not capped or frozen	Active	Yes, above and below base levels	4%
Arkansas	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	3%
Michigan	Not capped or frozen	Not capped or frozen	Active	Yes, in some areas	2%
Tennessee	Not capped or frozen	Not capped or frozen	Active	No	1%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2005.

(2) The PUCO has approved the rate stabilization plan filed by CSPCo and OPCo that begins after the market development period and extends through December 31, 2008 during which OPCo's retail generation rates will increase 7% annually and CSPCo's retail generation rates will increase 3% annually. Distribution rates are frozen, with certain exceptions, through December 31, 2008.

(3) Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.

(4) Fuel rates capped through June 2007 billing month at increasing rates subject to certain events at the Cook Plant.

(5) Legislation passed in 2004 capped base rates until December 31, 2010 and expanded the rate change opportunities to one full rate case (including generation, transmission and distribution) between July 1, 2004 and June 30, 2007 and one additional full rate case between July 1, 2007 and December 31, 2010. The new law also permits APCo to recover, on a timely basis, incremental costs incurred on and after July 1, 2004 for transmission and distribution reliability purposes and to comply with state and federal environmental laws and regulations.

(6) ENEC was suspended in West Virginia pursuant to a 1999 rate case stipulation. We are seeking to reactivate ENEC and have received approval from the WVPSC to begin deferral accounting associated with it effective July 1, 2006

(7) Includes, where applicable, fuel and fuel portion of purchased power.

FERC

Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require AEP to provide open access transmission service at FERC-approved rates. FERC also regulates unbundled transmission service to retail customers. FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from FERC, under which most of its wholesale marketing activity takes place.

As a result of PUHCA's repeal, jurisdiction over certain holding company related activities has been transferred to the FERC. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators will be permitted to review the books and records of any company within a holding company system. EPACT gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight.

ELECTRIC RESTRUCTURING AND CUSTOMER CHOICE LEGISLATION

Certain states in AEP's service area have adopted restructuring or customer choice legislation. In general, this legislation provides for a transition from bundled cost-based rate regulated electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier. At a minimum, this legislation allows retail customers to select alternative generation suppliers. Electric restructuring and/or customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and the ERCOT area of Texas. Electric restructuring in the SPP area of Texas has been delayed by the PUCT until at least 2007. AEP's public utility subsidiaries operate in both the ERCOT and SPP areas of Texas.

See Note 5 to the consolidated financial statements, entitled *Effects of Regulation*, included in the 2005 Annual Reports, for a discussion of the effect of restructuring and customer choice legislation on accounting procedures. See Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* for additional information.

Ohio Restructuring

The Ohio Act requires vertically integrated electric utility companies that offer competitive retail electric service in Ohio to separate their generating functions from their transmission and distribution functions. Following the market development period (which ended December 31, 2005), retail customers receive distribution and, where applicable, transmission service from the incumbent utility whose distribution rates are approved by the PUCO and whose transmission rates are approved by the FERC. The PUCO approved CSPCo's and OPCo's rate stabilization plans that, among other things, addressed default generation service rates from January 1, 2006 through December 31, 2008. See *Item 1 – Utility Operations - Regulation—FERC* for a discussion of FERC regulation of transmission rates, *Regulation—Rates—Ohio* and Note 4 to the consolidated financial statements entitled *Rate Matters*, included in the 2005 Annual Reports, for a discussion of the impact of restructuring on distribution rates. The PUCO authorized CSPCo and OPCo to remain functionally separated through the end of that three-year period. The PUCO's order has been appealed to the Supreme Court of Ohio by the Ohio Consumers' Counsel.

Texas Restructuring

Signed into law in June of 1999, the Texas Act substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition for all customers. Among other things, the Texas Act:

- gave Texas customers the opportunity to choose their REP beginning January 1, 2002 (delayed until at least 2007 in the SPP portion of Texas),
- required each utility to legally separate into a REP, a power generation company, and a transmission and distribution utility, and
- required that REPs provide electricity at generally unregulated rates, except that until January 1, 2007 the prices that may be charged to residential and small commercial customers by REPs affiliated with a utility within the affiliated utility's service area are set by the PUCT, until certain conditions in the Texas Act are met.

The Texas Act provides each affected utility an opportunity to recover its generation related regulatory assets and stranded costs resulting from the legal separation of the transmission and distribution utility from the generation facilities and the related introduction of retail electric competition. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account, as ultimately determined in a PUCT true-up proceeding.

In May 2005, TCC filed its stranded cost quantification application, or true-up proceeding, with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in February 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal seeking additional recovery consistent with the Texas Act and related rules. For a discussion of

(i) regulatory assets and stranded costs subject to recovery by TCC and (ii) rate adjustments made after implementation of restructuring to allow recovery of certain costs by or with respect to TCC and TNC, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* included in the 2005 Annual Reports.

Michigan Customer Choice

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Rates for retail electric service for I&M's Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2005, none of I&M's Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Virginia Restructuring

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

COMPETITION

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketeers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with the various state commissions. Occasionally, these rates are first negotiated, and then filed with the state commissions. The public utility subsidiaries believe that they are unlikely to be materially adversely affected by this competition.

SEASONALITY

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

INVESTMENTS

GAS OPERATIONS

In January 2005, we sold a 98% controlling interest in HPL and related assets with the remaining 2% interest being sold to the buyer in November 2005. See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Other Losses,* included in the 2005 Annual Reports for more information. As a result, management anticipates that our gas marketing operations will be limited to managing our obligations with respect to the gas transactions entered into before these sales.

OTHER

General

Through certain subsidiaries, AEP conducts certain business operations other than those included in other segments in which it uses and manages a portfolio of energy-related assets. The assets currently used and managed include:

- 791 MW of domestic power generation facilities (of which AEP ownership is approximately 551 MW);
- Undeveloped and formerly operated coal properties and related facilities; and
- Barge, rail and other fuel transportation related assets.

These operations include the following activities:

- Entering into long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities at various locations in North America;
- Holding various properties, coal reserves and royalty interests and reclaiming formerly operated mining properties in Colorado, Indiana, Kentucky, Louisiana, Ohio, Texas, Utah and West Virginia; and
- Through AEP MEMCO LLC, transporting coal and dry bulk commodities, primarily on the Ohio, Illinois, and Lower Mississippi rivers for AEP, as well as unaffiliated customers. Through subsidiaries, AEP owns or leases more than 7,000 railcars, 2,300 barges, 53 towboats and a coal handling terminal with 20 million tons of annual capacity.

AEP has in the past three years written down the value of certain of these investments. See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Other Losses,* included in the 2005 Annual Reports.

Dow Chemical Cogeneration Facility

Pursuant to an agreement with Dow, AEP constructed a 880 MW cogeneration facility ("Facility") at Dow's chemical facility in Plaquemine, Louisiana that achieved commercial operation status on March 18, 2004. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to Tractebel at a price that is currently in excess of market. Tractebel alleged that the power purchase agreement was unenforceable. This agreement is now being litigated. A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that Tractebel had breached the contract and awarded us damages of $123 million plus prejudgment interest. Both parties have filed appeals. In January 2006, the trial court increased AEP's judgment against Tractebel to $173 million plus prejudgment interest. The power from the Facility is currently sold on the market. See Notes 7 and 10 to the consolidated financial statements, entitled *Commitments and Contingencies* and *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Other Losses*, respectively, included in the 2005 Annual Reports, for more information.

ITEM 1A. RISK FACTORS

General Risks of Our Regulated Operations

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the price of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could cause our financial results to be diminished.

Our request for rate recovery of additional costs may not be approved in Virginia. *(Applies to AEP and APCo.)*

On July 1, 2005, APCo filed a request with the VSCC seeking approval for the recovery of $62 million in incremental costs through June 30, 2006. The $62 million request included incurred and projected costs of environmental controls, transmission costs (including line construction) and other system reliability work. In October 2005, the VSCC ruled that it does not have the authority to approve the recovery of projected costs. In November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery to $21 million. The staff of the VSCC has made filings to dismiss the transmission system reliability costs from consideration for recovery, arguing that the FERC, and not the VSCC, has jurisdiction over the unbundled transmission component of APCo's retail rates. Through December 31, 2005, APCo has deferred $24 million of recorded costs that are subject to this proceeding (which does not include $4 million of related equity carrying costs). The staff of the VSCC has issued testimony that would reduce APCo's recovery of current and future costs to $20 million. If the VSCC denies recovery of any of APCo's deferred costs, it would adversely impact future results of operations and cash flows.

Our request for rate recovery of additional costs may not be approved in West Virginia. *(Applies to AEP and APCo.)*

In August 2005, APCo and WPCo collectively filed an application (amended in January 2006) with the WVPSC seeking an initial increase in their retail base rates of approximately $73 million. Most of the requested base rate increase is attributable to reactivating the currently suspended ENEC mechanism that provides recovery of power supply costs, including fuel and purchased power, while the rest is primarily related to the recovery of the costs associated with the Ceredo Generating Station and service reliability improvements. The first supplemental increase of $9 million, requested to be effective at the same time as the base rate change, provides for recovery of the capital costs of the Wyoming Jackson's Ferry 765kV line. The remaining proposed supplemental increases are $43 million, $8 million and $36 million, to be effective on January 1, 2007, 2008 and 2009, respectively, provide for recovery of environmental expenditures. APCo has a regulatory liability of $52 million of pre-suspension, previously over-recovered ENEC costs which, along with a carrying cost, it is proposing to apply in the future to any future under-recoveries of ENEC costs through the reactivated ENEC mechanism. The WVPSC has granted a joint motion that requested hearings begin April 17, 2006, that new rates go into effect on July 28, 2006 and that deferral accounting for over- or under-recovery of the ENEC begin July 1, 2006. If the WVPSC denies the requested rate recovery, it could adversely impact future results of operations and cash flows.

Our request for rate recovery of additional costs may not be approved in Kentucky. *(Applies to AEP and KPCo.)*

In September 2005, KPCo filed a request with the Kentucky Public Service Commission to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase included a return on common equity of 11.5% or $26 million, the recovery of transmission costs of $10 million, the recovery of additional capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. We have entered into a settlement agreement with intervenors that provides an increase in base rates of approximately $41 million. If the Kentucky Public Service Commission does not approve the settlement or otherwise denies the requested rate recovery, it could adversely impact future results of operations and cash flows.

We may not be able to recover all of our fuel costs in Indiana. *(Applies to AEP and I&M.)*

In 2003, I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement. The IURC approved the agreement on June 1, 2005. The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at increasing rates during agreed-upon intervals. I&M experienced a cumulative under-recovery of fuel costs for the period March 2004 through December 2005. If future fuel costs through June 30, 2007 continue to exceed the agreed-upon caps, future results of operations and cash flows would be adversely affected.

The rates that SWEPCo may charge its customers may be reduced. *(Applies to SWEPCo.)*

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Separately, at the time of the CSW merger, SWEPCO agreed to file with the LPSC detailed financial information typically utilized in a revenue requirement filing on a periodic basis in order to demonstrate the lack of adverse impact from the merger. The first such filing was in October 2002 and the second was in April 2004. While both filings indicated that SWEPCo's rates should not be reduced, direct testimony filed by staff of the LPSC recommends a $15 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo has filed rebuttal testimony and additional discovery is planned. In a separate matter, in November 2005 the

LPSC included SWEPCo in an inquiry initiated to determine whether utilities had purchased fuel and power at the lowest possible price and whether suppliers offered competitive prices for fuel and purchased power during the period of January 1, 2005 through October 31, 2005. As a result, the LPSC is conducting an audit of SWEPCo's historical fuel costs for the years 2003 and 2004. At this time, management is unable to predict the outcome of these proceedings. If a rate reduction is ordered in the future, it would adversely impact future results of operations and cash flows.

The amount that PSO seeks to recover for fuel costs is currently being reviewed. *(Applies to PSO.)*

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP's West zone public utility subsidiaries of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC offering to collect the under-recovery over 18 months. An intervenor, the staff of the OCC and the Attorney General of Oklahoma have made filings indicating that recovery should be reduced substantially or disallowed altogether. These filings disputed the allocation of AEP System off-system sales margins pursuant to an agreement approved by FERC. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. The allocation issue was referred to an ALJ. The ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. The OCC conducted a hearing on the jurisdictional matter in January 2005 but has not issued a decision. If the OCC determines, as a result of the review, that a portion of PSO's fuel and purchased power costs should not be recovered, there could be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

The internal allocation of AEP System off-system sales margins has been challenged. *(Applies to APCo, CSPCo, I&M, KPCo and OPCo.)*

Off-system sales margins are allocated among the AEP System companies pursuant to a FERC-approved agreement among those companies entered into at the time of the merger with CSW. In November 2005, we filed with the FERC a proposed allocation methodology to be used in 2006 and beyond. The original allocations have been challenged in different forums, including PSO's fuel clause recovery proceeding before the OCC. In general, the challenges assert that AEP's West zone public utility subsidiaries, acquired in the merger with CSW, are being allocated a disproportionately small amount of the off-system sales margins. An ALJ in the OCC proceeding and, separately, a federal district court in Texas have each held that the FERC is the only appropriate adjudicator of such challenges. No proceeding questioning the allocation of our off-system sales is currently before the FERC; the OCC, however, has yet to rule on whether it has jurisdiction over this issue. If the FERC or another entity of competent authority were to retroactively allocate additional off-system sales margins to the West zone public utility subsidiaries, the East zone public utility subsidiaries may be required to pay money to the West zone public utility subsidiaries. Any such payments could have an adverse effect on the results of operations, cash flows and possibly financial condition of the East zone public utility subsidiaries.

The base rates that certain of our utilities charge are currently capped or frozen. *(Applies to AEP, CSPCo, I&M and OPCo.)*

Base rates charged to customers in Michigan and Ohio are currently either frozen or capped. To the extent our costs in these states exceed the applicable cap or frozen rate, those costs are not recoverable from customers.

Certain of our revenues and results of operations are subject to risks that are beyond our control. *(Applies to each registrant.)*

Unless mitigated by timely and adequate regulatory recovery, the cost of repairing damage to our utility facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of insurance coverage, when applicable, may adversely impact our revenues, operating and capital expenses and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials.

We are exposed to nuclear generation risk. *(Applies to AEP and I&M.)*

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,143 MW, or 6% of our generation capacity. We are, therefore, subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others); and,
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at a nuclear facility in the U.S. could require us to make material contributory payments.

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to each registrant.)*

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the operation of new regional transmission organizations, or "RTOs", may restrict our ability to sell power produced by our generating capacity to certain markets if there is insufficient transmission capacity otherwise available. The rules governing the various regional power markets may also change from time to time which could affect our costs or revenues. Because it remains unclear which companies will be participating in the various regional power markets, or the manner in which RTOs will evolve or the regions they will cover, we are unable to assess fully the impact that these power markets may have on our business.

AEP's East zone public utility subsidiaries joined PJM on October 1, 2004. SWEPCo and PSO are members of SPP. In February 2004, FERC granted RTO status to SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings.

The utility commissions of Louisiana and Arkansas are concerned about the effect on retail ratepayers of utilities in Louisiana and Arkansas joining RTOs. These commissions have ordered the utilities in those states, including us, to analyze and submit to them the costs and benefits of RTO options available to the utilities. Certain states in the region have undertaken and released a study investigating the costs and benefits of SPP developing into a RTO that administers energy and associated markets.

To the extent we are faced with conflicting state and Federal requirements as to our participation in RTOs, it could adversely affect our ability to operate and recover transmission costs from retail customers. Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, our transmission operations or future results of operations and cash flows.

The amount we charge third parties for using our transmission facilities may be reduced and not recovered. *(Applies to AEP and AEP's East zone public utility subsidiaries.)*

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and PJM expanded regions (Combined Footprint). The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost adjustment (SECA) transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision and SECA fees are being collected subject to refund while FERC considers the issue.

SECA transition rates have not fully compensated AEP for lost T&O revenues. AEP's East zone public utility subsidiaries received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the last twelve months prior to joining PJM. AEP's East zone public utility subsidiaries recognized net SECA revenues of $128 million in 2005. SECA transition rates expire at the end of March 2006, after which, all transmission costs that would otherwise have been covered by T&O rates in the Combined Footprint will be subject to recovery from native load customers of AEP's East zone public utility subsidiaries. A rate request is pending in West Virginia and a settlement agreement is pending in Kentucky that address the reduction in these transmission revenues. In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. At this time, management is unable to predict whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers.

In addition to seeking retail rate recovery from the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of our respective transmission assets. A majority of PJM members have filed in opposition to the proposal. The case is scheduled for hearing in April 2006. AEP management cannot at this time estimate the outcome of the proceeding.

Rate regulation may delay or deny full recovery of costs. *(Applies to each registrant.)*

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. Additionally, there may also be a delay between the timing of when these costs are incurred and when these costs are recovered. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner.

We operate in a non-uniform and fluid regulatory environment. *(Applies to each registrant.)*

In addition to the multiple levels of state regulation at the states in which we operate, our business is subject to extensive federal regulation. There can be no assurance that (1) the federal legislative and regulatory initiatives (which have occurred over the past few years and which have generally facilitated competition in the energy sector) will continue or will not be reversed or (2) state regulation will not become significantly more restrictive. Further alteration of the regulatory landscape in which we operate will impact the effectiveness of our business plan and may, because of the continued uncertainty, harm our financial condition and results of operations.

At times, demand for power could exceed our supply capacity. *(Applies to each registrant other than TCC and TNC.)*

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power from the market. We may not always have the ability to pass these costs on to our customers because some of the states we operate in do not allow us to increase our rates in response to increased fuel cost charges. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage were brief, we could suffer substantial losses that could reduce our results of operations.

Risks Related to Market, Economic or Financial Volatility

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant other than AEGCo.)*

Following the bankruptcy of Enron, the credit ratings agencies initiated a thorough review of the capital structure and the quality and stability of earnings of energy companies, including us. The agencies revised ratings at that time. Further negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the registrants, particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. *(Applies to AEP.)*

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP would be subject to regulatory or contractual restrictions.

Our operating results may fluctuate on a seasonal and quarterly basis. *(Applies to each registrant.)*

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. We expect that unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. As a result, we have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. We are therefore exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. *(Applies to each registrant.)*

We are heavily exposed to changes in the price and availability of coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are heavily exposed to changes in the price and availability of emission allowances. We use emission allowances in direct proportion with the amount of coal we use as fuel. According to our estimates we have procured sufficient emission allowances to cover our projected needs for the next two years and for much of the projected needs for periods beyond that. At some point, however, we will have to obtain additional allowances and those purchases may not be on as favorable terms as those currently obtained.

We also own natural gas-fired facilities, which increases our exposure to the more volatile market prices of natural gas.

The price trends for coal, natural gas and emission allowances have shown material increases that are expected to continue. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers. In addition, the prices we can charge our retail customers in some jurisdictions are capped and our fuel recovery mechanisms in other states are frozen for various periods of time.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

In certain jurisdictions, we have limited ability to pass on our fuel costs to our customers. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

We are exposed to risk from changes in the market prices of coal, natural gas, and emissions used to generate power where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The prices of coal, natural gas and emissions have increased materially over the past several years, and that trend is expected to continue. The protection afforded by retail fuel clause recovery mechanisms has been eliminated by the implementation of customer choice in Ohio. Because the risk of generating costs cannot be passed through to customers as a matter of right in Ohio, we retain these risks.

We have applied to reactivate the mechanism that provides recovery of power supply costs, including fuel, in West Virginia; the mechanism was suspended by a settlement reached in a state restructuring proceeding. The WVPSC has approved commencement of deferral accounting related to power supply costs, including fuel, effective July 1, 2006. A recently negotiated fuel cap in Indiana may not allow us to fully recover our fuel costs there. If we cannot recover an amount sufficient to cover our actual fuel costs, our results of operations and cash flows would be adversely affected.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP.)*

On June 1, 2001, we purchased Houston Pipe Line Company ("HPL") from Enron Corp. ("Enron"). Later that year, Enron and its subsidiaries filed bankruptcy proceedings in the U.S. Bankruptcy Court for the Southern District of New York. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 BCF of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America ("BOA") and certain other banks (together with BOA, "BOA Syndicate") and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Additionally, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We are currently litigating the rights to the cushion gas.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In 2005 we sold HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Risks Relating To State Restructuring

We may be required to serve former large industrial or commercial customers in Ohio at rates that are below market. *(Applies to AEP, CSPCo and OPCo.)*

Large industrial or commercial customers in Ohio who switched from us to alternative suppliers when customer choice became effective may successfully petition the PUCO to require us to provide service to them at prices that may be below market or that do not allow us to recover our costs. This may increase demand above our facilities' available capacity or limit our ability to earn a return on the sale of power. Thus, any such switching by customers could have an adverse effect on our results of operations and financial position. Additionally, to the extent the power sold to meet the default service obligations could have been sold to third parties at more favorable wholesale prices, we will have incurred potentially significant lost opportunity costs.

Some laws and regulations governing restructuring in Virginia have not yet been interpreted or adopted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo.)*

Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January 1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with the VSCC and, following VSCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later VSCC consideration. While the electric restructuring law in Virginia established the general framework governing the retail electric market, it required the VSCC to issue rules and determinations implementing the law. Some of the regulations governing the retail electric market have not yet been adopted by the VSCC. When the regulations are developed and adopted, compliance with them may harm our business, results of operations and financial condition.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP and TCC.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of the generation assets of TCC for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in February 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal seeking additional recovery consistent with the Texas Act and related rules. If, after appeal, the amount of recovery is reduced or we are otherwise unable to recover all or part of the net stranded generation costs and other recoverable true-up items, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP, TCC and TNC.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately sixty REPs. Adverse economic conditions, structural problems in the new Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to each registrant other than TCC.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules, and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from the estimates. All of the costs are incremental to our current investment base and operating cost structure.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to each registrant other than TCC.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the Clean Air Act. EPA and a number of states alleged that we and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the EPA case. The alleged modification of the generating units occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded, but no decision has been issued. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that carbon dioxide emissions from power generating facilities constitute a public nuisance under federal common law. The suits were dismissed by the trial court and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing carbon dioxide emissions could harm our business and our results of operations and financial position.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control. *(Applies to each registrant other than TCC.)*

We sell power from our generation facilities into the spot market or other competitive power markets or on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, we are generally not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices may fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations.

Volatility in market prices for fuel and power may result from:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. *(Applies to each registrant other than TCC.)*

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure by establishing and enforcing of risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

Our financial performance may be adversely affected if we are unable to operate our pooled electric generating facilities successfully. *(Applies to each registrant other than TCC.)*

Our performance is highly dependent on the successful operation of our electric generating facilities. Operating electric generating facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions caused by transportation constraints, adverse weather, non-performance by our suppliers and other factors; and
- catastrophic events such as fires, earthquakes, explosions, hurricanes, terrorism, floods or other similar occurrences.

A decrease or elimination of revenues from power produced by our electric generating facilities or an increase in the cost of operating the facilities would adversely affect our results of operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We are contractually required to operate a power generation facility that may indirectly force us to sell the facility's excess energy at a loss. *(Applies to AEP.)*

We have agreed to lease from Juniper Capital L.P. a non-regulated merchant power generation facility ("Facility") near Plaquemine, Louisiana. We sublease the Facility to Dow. We operate the Facility for Dow. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to Tractebel at a price that is currently in excess of market. Tractebel alleged that the power purchase agreement was unenforceable. This agreement is now being litigated. A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that Tractebel had breached the contract and awarded us damages of $123 million plus prejudgment interest. Both parties have filed appeals. In January 2006, the trial court increased AEP's judgment against Tractebel to $173 million plus prejudgment interest. If the trial award is reversed or if Tractebel does not pay the judgment, our cash flow will be adversely affected. If the power agreement is held to be unenforceable, we will be required to find new purchasers for up to 800 MW. There can be no assurance that the power produced will be sold at prices that will exceed our costs to produce it. If that were the case, as a result of our obligations to Dow, we would be required to operate the Facility at a loss.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. *(Applies to each registrant other than TCC.)*

We depend on transmission facilities owned and operated by other unaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. *(Applies to each registrant other than TCC.)*

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

GENERAL

At December 31, 2005, the AEP System owned (or leased where indicated) generating plants with net power capabilities (east zone public utility subsidiaries-winter rating; west zone public utility subsidiaries-summer rating) shown in the following table:

Company	Stations		Coal MW	Natural Gas MW		Hydro MW	Nuclear MW	Lignite MW	Oil MW		Total MW
AEGCo	1	(a)	1,300								1,300
APCo	17	(b)(c)(d)	5,073	526		798					6,397
CSPCo	6	(e)(f)	2,345	852							3,197
I&M	9	(a)	2,295			11	2,143				4,449
KPCo	1		1,060								1,060
OPCo	8	(b)(g)(d)	8,472			48					8,520
PSO	8	(h)	1,018	3,238					25		4,281
SWEPCo	9	(i)	1,848	1,821				842			4,511
TCC	1	(h)(j)	54								54
TNC	11	(h)	377	1,014	(k)				10	(l)	1,401
Totals:	66		23,842	7,451		857	2,143	842	35		35,170

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.

(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.

(c) APCo acquired the Ceredo Generation Station, a 526 MW gas-fired unit in West Virginia, in December 2005.

(d) APCo owns Units 1 and 3 and OPCo owns Units 2, 4 and 5 of Philip Sporn Plant, respectively.

(e) CSPCo owns generating units in common with CG&E and DP&L. Its percentage ownership interest is reflected in this table.

(f) Unit 1 and Unit 2 of the Conesville Plant were retired by CSPCo in December 2005. CSPCo acquired the Waterford Energy Center, a 852 MW gas-fired unit in Ohio, in September 2005.

(g) The scrubber facilities at the General James M. Gavin Plant are leased. OPCo is permitted to terminate the lease as early as 2010.

(h) PSO, TCC and TNC, along with two unaffiliated companies, jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.

(i) SWEPCo owns generating units in common with unaffiliated parties. Only its ownership interest is reflected in this table.

(j) Under the Texas Act, TCC is completing the final stages of exiting the generation business. As a result, TCC has sold most of its generation facilities, including STP, and has agreed to sell the remaining 54 MW which consists of its portion of the Oklaunion power station.

(k) TNC's gas fired generation is deactivated.

(l) TNC's oil fired generation is deactivated.

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities. Information concerning these facilities at December 31, 2005 is listed below.

Facility	Fuel	Location	Capacity Total MW	Ownership Interest	Status
Desert Sky Wind Farm	Wind	Texas	161	100%	Exempt Wholesale Generator(a)
Sweeney	Natural gas	Texas	480	50%	Qualifying Facility(b)
Trent Wind Farm	Wind	Texas	150	100%	Exempt Wholesale Generator(a)
Total (c)			791		

(a) As defined under rules issued pursuant to EPACT.

(b) As defined under the Public Utility Regulatory Policies Act of 1978

(c) Does not include 50% interest in Bajio, which was sold in February, 2006.

See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Other Losses,* included in the 2005 Annual Reports, for a discussion of AEP's disposition of independent power producer and foreign generation assets.

COOK NUCLEAR PLANT

The following table provides operating information relating to the Cook Plant.

	Cook Plant	
	Unit 1	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License (a)	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,036,000	1,107,000
Net Capacity Factors (b)		
2005	88.8%	97.1%
2004	97.0%	81.6%
2003 (c)	73.5%	74.5%
2002	86.6%	80.5%

(a) Cook Nuclear Plant received Nuclear Regulatory Commission approval on August 30, 2005 to extend the Operating License 20 years for both Unit 1 and Unit 2.

(b) Net Capacity Factor values since 2004 reflect Nominal Net Electrical Rating in Kilowatts of 1,036,000 (Unit 1) and 1,107,000 (Unit 2). Net Capacity Factor values for 2003 and earlier, however, reflect previous Nominal Net Electrical Rating in Kilowatts of 1,020,000 (Unit 1) and 1,090,000 (Unit 2).

(c) The capacity factors for both units of the Cook Plant were reduced in 2003 due to an unplanned maintenance outage to implement upgrades to the traveling water screens system following a fish intrusion.

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. I&M may also incur costs and experience reduced output at Cook Plant, because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured. Such costs may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
AEP System (a)	219,114 (b)	2,026
APCo	51,337	644
CSPCo (a)	14,059	—
I&M	21,989	615
Kingsport Power Company	1,349	—
KPCo	10,857	258
OPCo	30,684	509
PSO	21,145	—
SWEPCo	20,552	—
TCC	29,405	—
TNC	16,039	—
WPCo	1,697	—

(a) Includes 766 miles of 345kV jointly owned lines.

(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

TITLES

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

Substantially all the fixed physical properties and franchises of APCo and SWEPCo, except for limited exceptions, are subject to the lien of the mortgage and deed of trust securing the first mortgage bonds of each such company.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia, and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

GENERAL

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts $3.7 billion, $3.6 billion and $3.5 billion of construction expenditures for 2006, 2007 and 2008, respectively. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

PROPOSED TRANSMISSION FACILITIES

AEP has filed a proposal with the FERC and the PJM to build a new 765kV transmission line stretching from West Virginia to New Jersey. The proposed transmission corridor will span approximately 550 miles and is designed to reduce PJM congestion costs through enhancing transfer capability and also to reduce transmission line losses. It also is expected to improve reliability in the eastern transmission grid. AEP's proposed transmission line, called the AEP Interstate Project, would originate at AEP's Amos transmission station in Putnam County, WV, connect through Doubs Station in Frederick County, MD and terminate at the Deans Station in Middlesex County, NJ. The proposed route follows a corridor conceptually identified by PJM as a transmission route needed to address transmission congestion within the PJM footprint. Exact routing of the line would be determined after PJM approves the project. AEP will work with PJM, other affected transmission owners and stakeholders throughout the siting process. AEP also has filed with the DOE in its efforts to designate National Interest Electric Transmission Corridors (NIETC). EPACT provides for NIETC designation for areas that are experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. It is expected that a new AEP subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected costs are approximately $3 billion, which may be shared with other stakeholders. The anticipated in-service date is 2014 assuming three years to site and acquire rights-of-way and five years to build the line.

APCo is continuing construction of the Jacksons Ferry-Wyoming 765,000-volt transmission line. The WVPSC and the VSCC have issued certificates authorizing construction and operation of the line. On December 31, 2002, the U.S. Forest Service issued a final environmental impact statement and record of decision to allow the use of federal lands in the Jefferson National Forest for construction of a portion of the line. On May 11, 2004, the decision of the Forest Service was challenged by the Sierra Club in the United States District Court for the Western District of Virginia. APCo has intervened in that litigation. Construction of the line is underway and the project is scheduled to be completed by June 2006.

PROPOSED GENERATION FACILITIES

In conjunction with an environmental impact study issued in August 2004, we announced plans to construct a synthetic-gas-fired plant or plants of approximately 1,000 MW of capacity in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology. We estimate that this new plant or plants will cost up to approximately $1.2 billion of direct costs for a nominal 600 MW facility. We are currently performing site analysis and evaluation and at the same time working with state regulators and legislators to establish a framework for expedient recovery of this significant investment in new clean coal technology before final site selection.

The plans are contingent upon receiving adequate cost recovery through rates approved by the applicable commission prior to beginning construction. We have filed an application in West Virginia seeking a certificate of public convenience and necessity to construct an IGCC plant in New Haven, West Virginia. In Ohio we filed an application with the PUCO requesting the approval of a mechanism by which costs associated with constructing and operating an IGCC throughout the life of the facility can be recovered in rates authorized by the PUCO. We have also entered into an agreement with General Electric Company and Bechtel Power Corporation pursuant to which they are providing front-end engineering and design for a nominal 600 MW IGCC facility.

Our significant planned environmental investments in emission control installations at existing coal-fired plants and our commitment to IGCC technology reinforce our belief that coal will be a lower-emission domestic energy source of the future and further signals our commitment to investing in clean, environmentally safe technology. For additional information regarding anticipated environmental expenditures, see *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters.*

In the fourth quarter of 2005, PSO and SWEPCO each issued Requests for Proposals (RFPs) soliciting capacity and energy resource proposals to satisfy their customers' future electric power requirements. SWEPCO is seeking up to 500 MW of short-term peaking capacity and up to 1,600 MW of long-term generating resources comprised of peaking, intermediate and baseload generation by 2011. PSO is seeking 300 MW of short-term peaking resources by June 2008 and 600 of baseload generation by June 2011. In December 2005, PSO received four proposals totaling more than 1,100 MW, although one proposal was rejected for not conforming to bidding requirements. The remaining proposals, which are self-build options, continue to be evaluated. SWEPCO and PSO anticipate submitting self-build proposals in their respective RFPs processes. PSO received proposals in its base load RFP on February 16, 2006, totaling 3,500 MW, including three self-build proposals and three non-affiliate proposals. The RFPs are currently being evaluated.

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2003, 2004 and 2005 and current estimates of 2006, 2007 and 2008 construction expenditures, in each case excluding AFUDC and assets acquired under leases.

	2003 Actual	2004 Actual	2005 Actual	2006 Estimate	2007 Estimate	2008 Estimate
			(in thousands)			
AEP System (a)	$1,299,900	$1,613,800	$2,368,300	$3,722,600	$3,611,400	$3,537,700
AEGCo	22,200	15,700	15,200	14,300	30,000	39,700
APCo	263,000	428,400	589,100	942,800	691,500	751,700
CSPCo	125,200	142,100	163,900	342,700	473,700	553,400
I&M	160,200	177,700	294,300	311,200	278,700	262,000
KPCo	94,100	36,700	56,700	100,000	127,100	144,000
OPCo	255,100	315,400	694,100	1,070,400	954,500	581,600
PSO	84,100	82,300	133,700	278,700	342,800	408,700
SWEPCo	119,500	98,600	156,400	287,900	366,700	458,400
TCC	140,200	105,900	177,100	278,400	247,000	222,100
TNC	45,300	35,700	62,700	72,500	71,600	89,400

(a) Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP, I&M and other AEP System companies. See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies* for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, incorporated by reference in Item 8.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

AEP, APCo, I&M, OPCo, SWEPCo and TCC. None.

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of February 1, 2006.

Name	Age	Office (a)
Michael G. Morris	59	Chairman of the Board, President and Chief Executive Officer of AEP and of AEPSC
Carl L. English	59	President-Utility Group of AEP and of AEPSC
Thomas M. Hagan	61	Executive Vice President-AEP Utilities-West of AEPSC
John B. Keane	59	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC
Holly K. Koeppel	47	Executive Vice President-AEP Utilities-East of AEPSC
Venita McCellon-Allen	46	Senior Vice President-Shared Services of AEPSC
Robert P. Powers	51	Executive Vice President of AEP and Executive Vice President-Generation of AEPSC
Susan Tomasky	52	Executive Vice President and Chief Financial Officer of AEP and of AEPSC

(a) Before joining AEPSC in his current position in January 2004, Mr. Morris was Chairman of the Board, President and Chief Executive Officer of Northeast Utilities (1997-2003). Mr. Powers and Ms. Tomasky have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Messrs. Hagan and Powers, Ms. Koeppel and Ms. Tomasky became executive officers of AEP effective with their promotions to Executive Vice President on September 9, 2002, October 24, 2001, November 18, 2002 and January 26, 2000, respectively. As a result of AEP's realignment of its executive management team in July 2004, Mr. Keane became an executive officer of AEP. Before joining AEPSC in his current position in July 2004, Mr. Keane was President of Bainbridge Crossing Advisors. Before that, he was Vice President-Administration for Northeast Utilities (1998-2002). Mr. English joined AEP as President-Utility Group and became an executive officer of AEP on August 1, 2004. Before joining AEPSC in his current position in August 2004, Mr. English was President and Chief Executive Officer of Consumers Energy gas division (1999-2004). Ms. McCellon-Allen became an executive officer of AEP in April 2005. Before joining AEP in 2004, Ms. McCellon-Allen was Senior Vice President-Human Resources for Baylor Health Care System (2000-2004). All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of AEPSC, or both, as the case may be.

APCo, I&M, OPCo, SWEPCo and TCC. The names of the executive officers of APCo, I&M, OPCo, SWEPCo and TCC, the positions they hold with these companies, their ages as of February 1, 2006, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, I&M, OPCo, SWEPCo and TCC are elected annually to serve a one-year term.

Name	Age	Position	Period
Michael G. Morris (a)(b)	59	Chairman of the Board, President, Chief Executive Officer and Director of AEP	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of AEPSC, APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Chairman of the Board, President and Chief Executive Officer of Northeast Utilities	1997-2003
Carl L. English (c)	59	President-Utility Group of AEP and President-Utility Group and Director of AEPSC	2004-Present
		Director and Vice President of APCo, I&M, OPCo,	2004-Present

Name	Age	Position	Period
		SWEPCo and TCC	
		President and Chief Executive Officer of Consumers Energy gas division	1999-2004
Thomas M. Hagan (d)	61	Executive Vice President-AEP Utilities-West and Director of AEPSC	2004-Present
		Vice Chairman of the Board, Vice President and Director of TCC and SWEPCo	2004-Present
		Vice President and Director of APCo, I&M and OPCo	2002-2004
		Executive Vice President of AEP	2004
		Executive Vice President-Shared Services of AEPSC	2002-2004
		Senior Vice President-Governmental Affairs of AEPSC	2000-2002
John B. Keane (a)	59	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC	2004-Present
		Director of APCo, OPCo, SWEPCo and TCC	2004-Present
		President of Bainbridge Crossing Advisors	2003-2004
		Vice President-Administration-Northeast Utilities	1998-2002
Holly K. Koeppel (e)	47	Executive Vice President-AEP Utilities-East and Director of AEPSC	2004-Present
		Vice Chairman of the Board, Vice President and Director of APCo, I&M and OPCo	2004-Present
		Executive Vice President of AEP	2004
		Executive Vice President-Commercial Operations of AEPSC	2002-2004
		Vice President-New Ventures	2000-2002
Venita McCellon-Allen (c)	46	Director and Senior Vice President-Shared Services of AEPSC	2004-Present
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President-Human Resources for Baylor Health Care Systems	2000-2004
Robert P. Powers (a)	51	Executive Vice President of AEP	2004-Present
		Director-AEPSC	2001-Present
		Executive Vice President-Generation of AEPSC	2003-2004
		Director and Vice President of APCo, OPCo, SWEPCo and TCC	2001-Present
		Director of I&M	2001-Present
		Vice President of I&M	1998-Present
		Executive Vice President-Nuclear Generation and Technical Services of AEPSC	2001-2003
		Senior Vice President-Nuclear Operations of AEPSC	2000-2001
Susan Tomasky (a)	52	Executive Vice President and Chief Financial Officer of AEP and of AEPSC	2004-Present
		Chief Financial Officer of AEP	2001-2004
		Director of AEPSC	1998-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of AEPSC	2001-2004
		Executive Vice President-Legal, Policy and Corporate	2000-2001

Name	Age	Position	Period
		Communications of AEPSC	
		Senior Vice President and General Counsel of AEPSC	1998-2001

(a) Messrs. Keane, Morris and Powers and Ms. Tomasky are directors of AEGCo, CSPCo, KPCo, PSO and TNC.

(b) Mr. Morris is a director of Cincinnati Bell, Inc. and The Hartford Financial Services Group, Inc.

(c) Mr. English and Ms. McCellon-Allen are directors of CSPCo, KPCo, PSO and TNC.

(d) Mr. Hagan is a director of PSO and TNC.

(e) Ms. Koeppel is a director of CSPCo and KPCo.

APCo:

Name	Age	Position	Period
Dana E. Waldo	54	President and Chief Operating Officer of APCo and Kingsport Power Company	2004-Present
		President and Chief Executive Officer of West Virginia Roundtable	1999-2004

I&M:

Name	Age	Position	Period
Marsha P. Ryan	54	Director	2005-Present
		President and Chief Operating Officer of I&M	2004-Present
		Senior Vice President-Customer Operations of AEPSC	2000-2004
		Vice President of APCo, I&M, SWEPCo and TCC	2000-2004
		Vice President of CSPCo and OPCo	1996-2004

OPCo:

Name	Age	Position	Period
Kevin E. Walker	42	President and Chief Operating Officer of CSPCo, OPCo and WPCo	2004-Present
		Vice President of Consolidated Edison (New York)	2001-2004
		Vice President of Public Service of New Hampshire	2000-2001

SWEPCo:

Name	Age	Position	Period
Nicholas K. Akins	45	President and Chief Operating Officer of SWEPCo	2004-Present
		Vice President of AEPSC	2000-2004

TCC:

Name	Age	Position	Period
Charles R. Patton	46	President and Chief Operating Officer of TCC	2004-Present
		Vice President of Governmental and Environmental Affairs-Texas	2002-2004
		Vice President of State Governmental Affairs of AEPSC	2000-2002

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP. The information required by this item is incorporated herein by reference to the material under AEP *Common Stock and Dividend Information* in the 2005 Annual Report.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2005, 2004 and 2003 are incorporated by reference to the material under *Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss)* in the 2005 Annual Reports.

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended December 31, 2005 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
10/01/05 – 10/31/05	5	$ 80.69	-	$ -
11/01/05 – 11/30/05	14	81.50	-	-
12/01/05 – 12/31/05	-	-	-	-
Total	19	$ 81.29	-	$ -

(a) OPCo repurchased 19 shares of its 4.50% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.

ITEM 6. SELECTED FINANCIAL DATA

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, I&M, OPCo, SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2005 Annual Reports.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2005 Annual Reports.

AEP, APCo, I&M, OPCo, SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2005 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2005 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2005, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc. ("AEP"), AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each, together with AEP, a "Registrant" and collectively, together with AEP, the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each

Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2005, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2005 that materially affected, or are reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

Additional information required by this item of AEP, as a large accelerated filer, is incorporated by reference to *Management's Report on Internal Control over Financial Reporting,* included in the 2005 Annual Report.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Nominees for Director* and *Section 16(a) Beneficial Ownership Reporting Compliance* of the definitive proxy statement of AEP for the 2006 annual meeting of shareholders, to be filed within 120 days after December 31, 2005. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of each company for the 2006 annual meeting of stockholders, to be filed within 120 days after December 31, 2005. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

I&M, SWEPCo and TCC. The names of the directors and executive officers of I&M, SWEPCo and TCC, the positions they hold with I&M, SWEPCo and TCC, their ages as of February 1, 2006, and a brief account of their business experience during the past five years appear below or under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

I&M:

Name	Age	Position	Period
K. G. Boyd	54	Director	1997-Present
		Vice President-Fort Wayne Region Distribution Operations	2000-Present

Name	Age	Position	Period
Allen R. Glassburn	53	Director	2005-Present
		Director of Business Operations	2004-Present
		Managing Director of Business Operations of AEPSC	1996-2004
JoAnn N. Grevenow	53	Director	2005-Present
		Director of Business Operations	2004-Present
		Managing Director of Business Operations of AEPSC	1996-2004
Patrick C. Hale	51	Director	2003-Present
		Plant Manager, Rockport Plant	2003-Present
		Energy Production Manager, Rockport Plant	2001-2003
		Energy Production Manager, Mountaineer Plant (APCo)	1997-2001
Marc E. Lewis	50	Director	2001-Present
		Vice President-External Affairs	2005-Present
		Assistant General Counsel of AEPSC	2001-2005
		Senior Counsel of AEPSC	2000-2001
Susanne M. Moorman Rowe	56	Director and General Manager, Corporate Communications	2004-Present
		Director and General Manager, Community Services	2000-2004
		Manager, Customer Services Operations	1997-2000
Marsha P. Ryan	54	Director	2005-Present
		President and Chief Operating Officer of I&M	2004-Present
		Senior Vice President-Customer Operations of AEPSC	2000-2004
		Vice President of APCo, I&M, SWEPCo and TCC	2000-2004
		Vice President of CSPCo and OPCo	1996-2004

SWEPCo and TCC:

Name	Age	Position	Period
Stephen P. Smith (a)	44	Senior Vice President and Treasurer of AEP	2004-Present
		Senior Vice President-Corporate Accounting, Planning & Strategy, Treasurer and Director of AEPSC	2003-Present
		Treasurer of APCo, I&M, OPCo, SWEPCo and TCC	2003-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		President and Chief Operating Officer-Corporate Services for NiSource	1999-2003
Dennis E. Welch (b)	54	Senior Vice President of AEP	2005-Present
		Director of APCo, OPCo, SWEPCo AND TCC	2005-Present
		Senior Vice President-Environment and Safety and Director of AEPSC	2005-Present
		President of Yankee Gas Services Company	2001-2005

(a) Mr. Smith is a director of AEGCo, CSPCo, KPCo, PSO and TNC.

(b) Mr. Welch is a director of CSPCo, OPCo, PSO and TNC.

ITEM 11. EXECUTIVE COMPENSATION

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2006 annual meeting of shareholders to be filed within 120 days after December 31, 2005.

APCo, I&M and OPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2006 annual meeting of stockholders, to be filed within 120 days after December 31, 2005.

SWEPCo and TCC. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive proxy statement of AEP for the 2006 annual meeting of stockholders, to be filed within 120 days after December 31, 2005.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2006 annual meeting of shareholders to be filed within 120 days after December 31, 2005.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2006 annual meeting of stockholders, to be filed within 120 days after December 31, 2005.

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2006, by each director and nominee of I&M and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)	Stock Units (b)	Total
Karl G. Boyd	8,073	1,767	9,840
Carl L. English	—	28,461	28,461
Allen R. Glassburn	2,423	2,402	4,825
JoAnn N. Grevenow	2,700	868	3,568
Patrick C. Hale	2,010	—	2,010

Holly K. Koeppel	79,123		28,702	107,825
Marc E. Lewis	11,288		1,255	12,543
Venita McCellon-Allen	—		9,404	9,404
Suzanne M. Moorman Rowe	44		—	44
Michael G. Morris	400,418	(e)	164,034	564,452
Robert P. Powers	171,653	(c)	29,705	201,358
Marsha P. Ryan	29,141		9,102	38,243
Susan Tomasky	249,357	(c)	35,353	284,710
All Directors and Executive Officers	998,461	(c)(d)	311,053	1,309,514 (c)

Name	AEP Retirement Savings Plan (Share Equivalents)
Karl G. Boyd	372
Carl L. English	—
Allen R. Glassburn	705
JoAnn N. Grevenow	333
Patrick C. Hale	177
Holly K. Koeppel	256
Marc E. Lewis	1,555
Venita McCellon-Allen	—
Suzanne M. Moorman Rowe	44
Michael G. Morris	—
Robert P. Powers	685
Marsha P. Ryan	6,439
Susan Tomasky	3,357
All Directors and Executive Officers	13,923

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Boyd, 7,701; Mr. Glassburn, 1,718; Ms. Grevenow, 2,367; Mr. Hale, 1,833; Ms. Koeppel, 78,867; Mr. Lewis, 9,733; Mr. Morris, 99,333; Mr. Powers, 170,968; Ms. Ryan, 22,702; and Ms. Tomasky, 246,000.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) Does not include, for Ms. Tomasky, Ms. McCellon-Allen, Messrs. English and Powers, 42,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky, Ms McCellon-Allen, Messrs. English and Powers 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) Represents less than 1% of the total number of shares outstanding.
(e) Includes restricted shares with different vesting schedules and accrued dividends.

SWEPCo. All 7,536,640 outstanding shares of Common Stock, $18 par value, of SWEPCo are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of SWEPCo generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2006, by each director and nominee of SWEPCo and each of the executive officers of SWEPCo named in the summary compensation table, and by all directors and executive officers of SWEPCo as a group. It is based on information provided to SWEPCo by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of SWEPCo. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)		Stock Units (b)	Total	
Nicholas K. Akins	16,624		1,736	18,360	
Carl L. English	—		28,461	28,461	
Thomas M. Hagan	158,138		28,467	186,605	
John B. Keane	—		14,229	14,229	
Venita McCellon-Allen	—		9,404	9,404	
Michael G. Morris	400,418	(e)	164,034	564,452	
Robert P. Powers	171,653	(c)	29,705	201,358	
Stephen P. Smith	33,000		8,011	41,011	
Susan Tomasky	249,357	(c)	35,353	284,710	
Dennis E. Welch	—		9,987	9,987	
All Directors and Executive Officers	1,071,421	(c)(d)	329,387	1,400,808	(c)

Name	AEP Retirement Savings Plan (Share Equivalents)
Nicholas K. Akins	1,224
Carl L. English	—
Thomas M. Hagan	5,479
John B. Keane	—
Venita McCellon-Allen	—
Michael G. Morris	—
Robert P. Powers	685
Stephen P. Smith	—
Susan Tomasky	3,357
Dennis E. Welch	—
All Directors and Executive Officers	10,745

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Akins, 15,400; Mr. Hagan, 142,166; Mr. Morris, 99,333; Mr. Powers, 170,968; Mr. Smith, 33,000; and Ms. Tomasky, 246,000.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) Does not include, for Ms. Tomasky, Ms. McCellon-Allen, Messrs. English and Powers, 42,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky, Ms. McCellon-Allen, Messrs.

English and Powers 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) Represents less than 1% of the total number of shares outstanding.

(e) Includes restricted shares with different vesting schedules and accrued dividends.

TCC. All 2,211,678 outstanding shares of Common Stock, $25 par value, of TCC are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of TCC generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2006, by each director and nominee of TCC and each of the executive officers of TCC named in the summary compensation table, and by all directors and executive officers of TCC as a group. It is based on information provided to TCC by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of TCC. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)		Stock Units (b)	Total	
Carl L. English	—		28,461	28,461	
Thomas M. Hagan	158,138		28,467	186,605	
John B. Keane	—		14,229	14,229	
Venita McCellon-Allen	—		9,404	9,404	
Michael G. Morris	400,418	(e)	164,034	564,452	
Charles R. Patton	9,046		1,349	10,395	
Robert P. Powers	171,653	(c)	29,705	201,358	
Stephen P. Smith	33,000		8,011	41,011	
Susan Tomasky	249,357	(c)	35,353	284,710	
Dennis E. Welch	—		9,987	9,987	
All Directors and Executive Officers	1,063,843	(c)(d)	329,000	1,392,843	(c)

Name	AEP Retirement Savings Plan (Share Equivalents)
Carl L. English	—
Thomas M. Hagan	5,479
John B. Keane	—
Venita McCellon-Allen	—
Michael G. Morris	—
Charles R. Patton	329
Robert P. Powers	685
Stephen P. Smith	—
Susan Tomasky	3,357
Dennis E. Welch	—
All Directors and Executive Officers	9,521

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Hagan, 142,166; Mr. Morris, 99,333; Mr. Patton, 8,717; Mr. Powers, 170,968; Mr. Smith, 33,000; and Ms. Tomasky, 246,000.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) Does not include, for Ms. Tomasky, Ms. McCellon-Allen, Messrs. English and Powers, 42,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky, Ms. McCellon-Allen, Messrs. English and Powers 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) Represents less than 1% of the total number of shares outstanding.
(e) Includes restricted shares with different vesting schedules and accrued dividends.

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2005:

Plan Category	Number of securities to be issued upon exercise of outstanding options warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans [excluding securities reflected in column (a)] (c)
Equity compensation plans approved by security holders(1)	6,221,839	$34.164	16,235,192
Equity compensation plans not approved by security holders	0	N/A	0
Total	6,221,839	$34.164	16,235,192

(1) Consists of shares to be issued upon exercise of outstanding options granted under the Amended and Restated American Electric Power System Long-Term Incentive Plan and the CSW 1992 Long-Term Incentive Plan (CSW Plan). The CSW Plan was in effect prior to the consummation of the AEP-CSW merger. All unexercised options granted under the CSW Plan were converted into 0.6 options to purchase AEP common shares, vested on the merger date and will expire ten years after their grant date. No additional options will be issued under the CSW Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC: None.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP. The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2006 annual meeting of shareholders to be filed within 120 days after December 31, 2005.

APCo and OPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2006 annual meeting of stockholders, to be filed within 120 days after December 31, 2005.

AEGCo, CSPCo, I&M, KPCo, PSO, SWEPCo, TCC and TNC.

Each of the above is wholly-owned subsidiaries of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2006 annual meeting of shareholders to be filed within 120 days after December 31, 2005. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2004 and 2005, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the definitive proxy statement of AEP for the 2006 annual meeting of shareholders to be filed within 120 days after December 31, 2005.

	AEGCo		CSPCo		I&M	
	2005	2004	2005	2004	2005	2004
Audit Fees						
Financial Statement Audits	$165,550	$164,303	$672,646	$608,935	755,644	$679,061
Sarbanes-Oxley 404	100,619	112,341	465,626	518,610	440,366	490,537
Audit Fees – Other	29,628	19,530	145,287	57,660	139,603	49,290
Audit Fees Subtotal	295,797	296,174	1,283,559	1,185,205	1,335,613	1,218,888
Audit-Related Fees	0	0	55,500	5,000	5,500	184,000
Tax Fees	2,250	67,539	23,100	888,188	30,350	1,136,796
TOTAL	$298,047	$363,713	$1,362,159	$2,078,393	$1,371,463	$2,539,684

	KPCo		PSO		SWEPCo	
	2005	2004	2005	2004	2005	2004
Audit Fees						
Financial Statement Audits	$446,615	$413,013	$416,418	$357,053	$483,761	$411,970
Sarbanes-Oxley 404	255,547	284,581	245,864	273,793	285,438	318,007
Audit Fees – Other	71,972	36,270	89,098	24,180	99,190	27,900
Audit Fees Subtotal	774,134	733,864	751,380	655,026	868,389	757,877
Audit-Related Fees	0	0	5,500		5,500	10,000
Tax Fees	10,550	81,412	21,400	438,845	20,400	567,665
TOTAL	$784,684	$815,276	$778,280	$1,093,871	$894,289	$1,335,542

	TCC		TNC	
	2005	2004	2005	2004
Audit Fees				
Financial Statement Audits	$512,496	$446,899	$175,723	$159,950
Sarbanes-Oxley 404	320,802	357,257	168,821	188,080
Audit Fees – Other	170,027	46,500	48,337	26,040
Audit Fees Subtotal	1,003,325	850,656	392,881	374,070
Audit-Related Fees	0	21,500	0	8,325
Tax Fees	28,900	896,577	15,250	235,477
TOTAL	1,032,225	$1,768,733	$408,131	$617,872

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

	Page
1. **FINANCIAL STATEMENTS:**	
The following financial statements have been incorporated herein by reference pursuant to Item 8.	
AEGCo:	
Statements of Income for the years ended December 31, 2005, 2004 and 2003; Statements of Retained Earnings for the years ended December 31, 2005, 2004 and 2003; Balance Sheets as of December 31, 2005 and 2004; Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
AEP and Subsidiary Companies:	
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Operations for the years ended December 31, 2005, 2004 and 2003; Consolidated Balance Sheets as of December 31, 2005 and 2004; Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003; Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss) for the years ended December 31, 2005, 2004 and 2003; Notes to Consolidated Financial Statements.	
APCo, CSPCo, I&M, OPCo, SWEPCo and TCC:	
Consolidated Statements of Income (or Statements of Operations) for the years ended December 31, 2005, 2004 and 2003; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2005, 2004 and 2003; Consolidated Balance Sheets as of December 31, 2005 and 2004; Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
KPCo, PSO and TNC:	
Statements of Income for the years ended December 31, 2005, 2004 and 2003; Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2005, 2004 and 2003; Balance Sheets as of December 31, 2005 and 2004; Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
2. **FINANCIAL STATEMENT SCHEDULES:**	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Report of Independent Registered Public Accounting Firm	S-1
3. **EXHIBITS:**	
Exhibits for AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Executive Vice President and Chief Financial Officer)

Date: February 28, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, President, Chief Executive Officer And Director	February 28, 2006
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Executive Vice President and Chief Financial Officer	February 28, 2006
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 28, 2006
(iv) A Majority of the Directors:		
*E. R. BROOKS *DONALD M. CARLTON RALPH D. CROSBY, JR. *JOHN P. DESBARRES *ROBERT W. FRI *LINDA A. GOODSPEED *WILLIAM R. HOWELL *LESTER A. HUDSON, JR. *LIONEL L. NOWELL, III *RICHARD L. SANDOR *DONALD G. SMITH *KATHRYN D. SULLIVAN		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		February 28, 2006

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP GENERATING COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: February 28, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2006
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	February 28, 2006
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2006
(iv) A Majority of the Directors:		
* JOHN B. KEANE * ROBERT P. POWERS * STEPHEN P. SMITH		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		February 28, 2006

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP TEXAS CENTRAL COMPANY
AEP TEXAS NORTH COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: February 28, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2006
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	February 28, 2006
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2006
(iv) A Majority of the Directors:		
*CARL L. ENGLISH *THOMAS M. HAGAN *JOHN B. KEANE *VENITA MCCELLON-ALLEN *ROBERT P. POWERS *STEPHEN P. SMITH *DENNIS E. WELCH		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		February 28, 2006

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President and Chief Financial Officer)

Date: February 28, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2006
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	February 28, 2006
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2006
(iv) A Majority of the Directors:		
*CARL L. ENGLISH *JOHN B. KEANE *HOLLY K. KOEPPEL *VENITA MCCELLON-ALLEN *ROBERT P. POWERS *STEPHEN P. SMITH *DENNIS E. WELCH		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		February 28, 2006

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

INDIANA MICHIGAN POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President
and Chief Financial Officer)

Date: February 28, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2006
(ii) Principal Financial Officer:		
/s/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	February 28, 2006
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2006
(iv) A Majority of the Directors:		

*K. G. BOYD
*CARL L. ENGLISH
*ALLEN R. GLASSBURN
*JOANN N. GREVENOW
*PATRICK C. HALE
*HOLLY KELLER KOEPPEL
*MARC E. LEWIS
*VENITA MCCELLON-ALLEN
*ROBERT P. POWERS
*SUSANNE M. MOORMAN ROWE
*MARSHA P. RYAN

*By: /s/ SUSAN TOMASKY — February 28, 2006
(Susan Tomasky, Attorney-in-Fact)

INDEX TO FINANCIAL STATEMENT SCHEDULES

The following financial statement schedules are included in this report on the pages indicated:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, and have issued our reports thereon dated February 27, 2006 (which reports express unqualified opinions and, with respect to the report on the consolidated financial statements, includes an explanatory paragraph concerning the adoption of new accounting pronouncements in 2003, 2004 and 2005); such consolidated financial statements and reports are included in your 2005 Annual Report and are incorporated herein by reference. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio
February 27, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of AEP Texas Central Company and subsidiary, AEP Texas North Company, Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Kentucky Power Company, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively the "Companies") as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, and have issued our reports thereon dated February 27, 2006 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2003, 2004 and 2005 where applicable); such financial statements and reports are included in the Companies 2005 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio
February 27, 2006

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 77,175	$ 27,384	$ 24	$ 74,030	$ 30,553
Year Ended December 31, 2004	123,685	39,766	7,989	94,265	77,175
Year Ended December 31, 2003	107,578	55,087	7,234	46,214	123,685

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 3,493	$ 29	$ -	$ 3,379	$ 143
Year Ended December 31, 2004	1,710	3,493	-	1,710	3,493
Year Ended December 31, 2003	346	1,712	-	348	1,710

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

AEP TEXAS NORTH COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 787	$ 14	$ -	$ 783	$ 18
Year Ended December 31, 2004	175	787	-	175	787
Year Ended December 31, 2003	5,041	123	-	4,989	175

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 5,561	$ 3,304	$ 21	$ 7,081	$ 1,805
Year Ended December 31, 2004	2,085	3,059	4,201	3,784	5,561
Year Ended December 31, 2003	13,439	4,708	433	16,495	2,085

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 674	$ 408	$ -	$ -	$ 1,082
Year Ended December 31, 2004	531	577	187	621	674
Year Ended December 31, 2003	634	96	-	199	531

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 187	$ 819	$ -	$ 108	$ 898
Year Ended December 31, 2004	531	195	90	629	187
Year Ended December 31, 2003	578	37	-	84	531

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

KENTUCKY POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 34	$ 146	$ -	$ 33	$ 147
Year Ended December 31, 2004	736	43	27	772	34
Year Ended December 31, 2003	192	8	912	376	736

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 93	$ 1,425	$ -	$ 1	$ 1,517
Year Ended December 31, 2004	789	122	89	907	93
Year Ended December 31, 2003	909	42	18	180	789

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 76	$ 164	$ -	$ -	$ 240
Year Ended December 31, 2004	37	21	55	37	76
Year Ended December 31, 2003	84	37	-	84	37

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2005	$ 45	$ 534	$ -	$ 31	$ 548
Year Ended December 31, 2004	2,093	(2,079)	134	103	45
Year Ended December 31, 2003	2,128	103	-	138	2,093

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form pursuant to Item 14(c) of this report.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
REGISTRANT: AEGCo File No. 0-18135		
3(a)	Articles of Incorporation of AEGCo.	Registration Statement on Form 10 for the Common Shares of AEGCo, Ex 3(a).
3(b)	Copy of the Code of Regulations of AEGCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
10(a)	Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP.	Registration Statement No. 33-32752, Ex 28(a).
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B).
10(b)(2)	Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KPCo.	Registration Statement No. 33-32752, Ex 28(b)(2).
10(c)	Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); 1993 Form 10-K, Ex 10(c)(1-6)(B).
*13	Copy of those portions of the AEGCo 2005 Annual Report, which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated January 13, 1999.	1998 Form 10-K, Ex 3(c).
3(b)	By-Laws of AEP, as amended through December 15, 2003	2003 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c); Registration Statement No. 333-105532, Ex 4(d)(e)(f).
4(b)	Purchase Agreement dated as of March 8, 2005, between AEP and Merrill Lynch International	Form 10-Q, Ex. 4(a), March 31, 2005
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); 1990 Form 10-K, Ex 10(a)(3).
10(b)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K; Ex 10(b) 1988 Form 10-K, Ex 10(b)(2).

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
10(d)		Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.		2002 Form 10-K; Ex 10(d).
10(e)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(e)(1)
10(e)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(e)(2)
10(e)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(e)(3)
10(f)		Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.		Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); AEGCO 1993 Form 10-K, Ex 10(c)(1-6)(B); I&M 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)		Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested)		OPCo 1994 Form 10-K, Ex 10(l)(2).
10(h)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		1996 Form 10-K, Ex 10(l)
†10(i)		AEP Accident Coverage Insurance Plan for directors.		1985 Form 10-K, Ex 10(g)
†10(j)(1)		AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended March 10, 2005, formerly known as AEP Deferred Compensation and Stock Plan for Non-Employee Directors.		2003 Form 10-K, Ex 10(k)(1) Form 10-Q, Ex. 10(b), March 31, 2005
†10(j)(2)		AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended December 10, 2003.		2003 Form 10-K, Ex 10(k)(2).
†10(k)(1)(A)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.		2000 Form 10-K, Ex 10(j)(1)(A)
†10(k)(1)(B)		Guaranty by AEP of AEPSC Excess Benefits Plan.		1990 Form 10-K, Ex 10(h)(1)(B)
†10(k)(1)(C)		First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.		2002 Form 10-K; Ex 10(1)(1)(c)
*†10(k)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 19, 2005.		
†10(k)(3)		Service Corporation Umbrella Trust for Executives.		1993 Form 10-K, Ex 10(g)(3).
†10(l)(1)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(m)(1).
†10(l)(2)		Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.		2000 Form 10-K, Ex 10(s)
†10(l)(3)		Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.		2002 Form 10-K; Ex 10(m)(3)(A)
†10(l)(4)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K; Ex 10(m)(4)
*†10(l)(5)		Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English		Form 10-Q, Ex 10(b), September 30, 2004
†10(m)		AEP System Senior Officer Annual Incentive Compensation Plan.		1996 Form 10-K, Ex 10(i)(1)
†10(n)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		Form 10-Q, Ex 10, September 30, 1998
†10(n)(2)		First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.		2002 Form 10-K; Ex 10(o)(2)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(o)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005.	Form 10-Q, Ex 10(b), June 30, 2005.
†10(p)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(q)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(s)
†10(r)	AEP Change In Control Agreement, effective January 1, 2006.	Form 8-K, Ex 1, dated January 3, 2006
†10(s)(1)	Amended and Restated AEP System Long-Term Incentive Plan	Form 8-K, Item 10.1, dated April 26, 2005.
†10(s)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended	Form 10-Q, Ex. 10(c), September 30, 2004
†10(s)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(t)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	CSW 1998 Form 10-K, Ex 18, File No. 1-1443
†10(t)(2)	Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.	2003 Form 10-K, Ex 10(v)(3).
†10(t)(3)	Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997.	CSW 1998 Form 10-K, Ex 24, File No. 1-1443.
*†10(u)	Schedule of Non-Employee Directors' Annual Compensation	
†10(v)	Base Salaries for Named Executive Officers	Form 8-K, Item 1.01, dated December 13, 2005
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d).
3(b)	By-Laws of APCo, amended as of October 24, 2001.	2001 Form 10-K, Ex 3(e).
4(a)	Mortgage and Deed of Trust, dated as of December 1, 1940, between APCo and Bankers Trust Company and R. Gregory Page, as Trustees, as amended and supplemented.	Registration Statement No. 2-7289, Ex 7(b); Registration Statement No. 2-19884, Ex 2(1) Registration Statement No. 2-24453, Ex 2(n); Registration Statement No. 2-60015, Ex 2(b)(2-10) (12)(14-28); Registration Statement No. 2-64102, Ex 2(b)(29);

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
		Registration Statement No. 2-66457, Ex (2)(b)(30-31); Registration Statement No. 2-69217, Ex 2(b)(32); Registration Statement No. 2-86237, Ex 4(b); Registration Statement No. 33-11723, Ex 4(b); Registration Statement No. 33-17003, Ex 4(a)(ii), Registration Statement No. 33-30964, Ex 4(b); Registration Statement No. 33-40720, Ex 4(b); Registration Statement No. 33-45219, Ex 4(b); Registration Statement No. 33-46128, Ex 4(b)(c); Registration Statement No. 33-53410, Ex 4(b); Registration Statement No. 33-59834, Ex 4(b); Registration Statement No. 33-50229, Ex 4(b)(c); Registration Statement No. 33-58431, Ex 4(b)(c)(d)(e); Registration Statement No. 333-01049, Ex 4(b)(c); Registration Statement No. 333-20305, Ex 4(b)(c); 1996 Form 10-K, Ex 4(b); 1998 Form 10-K, Ex 4(b).
4(b)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a); Registration Statement No. 333-49071, Ex 4(b); Registration Statement No. 333-84061, Ex 4(b)(c); Registration Statement No. 333-81402, Ex 4(b)(c)(d); Registration Statement No. 333-100451, Ex 4(b); Registration Statement No. 333-123348, Ex 4(b)(c).
4(c)	Company Order and Officer's Certificate to The Bank of New York, dated June 7, 2005, establishing terms of 4.40% Senior Notes, Series J, due 2010 and 5% Senior Notes, Series K, due 2017.	Form 8-K, Ex 4(a), dated June 7, 2005
4(d)	Company Order and Officer's Certificate to The Bank of New York, dated September 29, 2005, establishing terms of 5.80% Senior Notes, Series L, due 2035.	Form 8-K, Ex 4(a), dated September 29, 2005
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); 1989 Form 10-K, Ex 10(a)(1)(F); 1992 Form 10-K, Ex 10(a)(1)(B)].
* 10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, Ex 10(b); AEP 1988 Form 10-K, Ex 10(b)(2).
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo,	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
†10(f)	AEP System Senior Officer Annual Incentive Compensation Plan	AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(g)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
†10(g)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(h)(1)(B).
*†10(g)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 19, 2005.	
†10(g)(3)	Umbrella Trust for Executives.	AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(h)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(i)(1).
†10(hi)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.
†10(hi)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K; Ex 10(i)(3).
*†10(h)(4)	Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English	AEP Form 10-Q, Ex 10(b), September 30, 2004
†10(i)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
†10(i)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(j)(2).
†10(j)	AEP Change In Control Agreement, effective January 1, 2006.	Form 8-K, Ex 1 dated January 3, 2006,
†10(k)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 8-K, Ex 10.1, dated April 26, 2005.
†10(k)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended	AEP Form 10-Q, Ex. 10(c), dated November 5, 2004.
†10(kl)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	AEP Form 10-Q, Ex 10(a), March 31, 2005
†10(l)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	CSW 1998 Form 10-K, Ex 18, File No. 1-1443.
†10(l)(2)	Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.	2003 Form 10-K, Ex 10(n)(3).
†10(m)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005.	2003 Form 10-K, Ex 10(o)(1); Form 10-Q, Ex 10(b), June 30, 2005.
†10(n)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K; Ex 10(p).
†10(o)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(q).
†10(p)	Base Salaries for Named Executive Officers	Form 8-K, Item 1.01, dated December 13, 2005
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*23	Consent of Deloitte & Touche LLP	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: CSPCo‡ File No. 1-2680		
3(a)	Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994.	1994 Form 10-K, Ex 3(c).
3(b)	Code of Regulations and By-Laws of CSPCo.	1987 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d); Registration Statement No. 333-128174, Ex 4(d,
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g)
4(b)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated October 14, 2005, establishing terms of 5.85% senior Notes, Series F, due 2035.	Form 8-K, Ex 4(a), dated October 14, 2005.
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(B); APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457.
* 10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No.1-3457.
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525; AEP 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525.
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the CSPCo 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of CSPCo	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: I&M‡ File No. 1-3570		
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997	1996 Form 10-K, Ex 3(c).
3(b)	By-Laws of I&M, amended as of November 28, 2001.	2001 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c); Registration Statement No. 333-58656, Ex 4(b)(c); Registration Statement No. 333-108975, Ex 4(b)(c)(d)].
4(b)	Company Order and Officer's Certificate, dated November 10, 2004, establishing terms of 5.05% Senior Notes, Series F, due 2014.	Form 8-K, Ex. 4(a), dated November 16, 2004
4(c)	Company Order and Officer's Certificate to The Bank of New York, dated December 12, 2005, establishing terms of 5.65% Senior Notes, Series G, due 2015.	Form 8-K, Ex. 4(a), dated December 12, 2005
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
* 10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended	Registration Statement No. 2-60015, Ex 5(e).
10(a)(4)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-KEx 10(b), File No. 1-3525; AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
10(d)(1)	Amended and Restated Operating Agreement of PJM and	2004 Form 10-K, Ex 10(d)(1)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); 1993 Form 10-K, Ex 10(e)(1-6)(B).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of I&M.	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: KPCo‡ File No. 1-6858		
3(a)	Restated Articles of Incorporation of KPCo.	1991 Form 10-K, Ex 3(a).
3(b)	By-Laws of KPCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between KPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-75785, Ex 4(a)(b)(c)(d); Registration Statement No. 333-87216, Ex 4(e)(f); 2002 Form 10-K, Ex 4(c)(d)(e) 2003 Form 10-K, Ex4(b).
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(b)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525. AEP 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525.
10(c)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(c)(1)
10(c)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(c)(2)
10(c)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power	2004 Form 10-K, Ex 10(c)(3)

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		Company.		
10(d)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525,.
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the KPCo 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.		
*23		Consent of Deloitte & Touche LLP		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: OPCo‡ File No.1-6543				
3(a)		Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.		Form 10-Q, Ex 3(e), June 30, 2002.
3(b)		Code of Regulations of OPCo.		1990 Form 10-K, Ex 3(d).
4(a)		Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.		Registration Statement No. 333-49595, Ex 4(a)(b)(c); Registration Statement No. 333-106242, Ex 4(b)(c)(d); Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c).
4(d)		Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated November 16, 2005, establishing terms of 5.30% Senior Notes, Series J, due 2010		Form 8-K, Ex 4(a), dated November 16, 2005
4(e)		Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.		Registration Statement No. 333-127913, Ex 4(d)(e)(f).
10(a)(1)		Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.		Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
* 10(a)(2)		Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.		Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(a)(3)		Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.		Registration Statement No. 2-60015, Ex 5(e).
10(b)		Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.		Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File 1-3525.
10(c)		Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.		AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525, AEP 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525.
10(d)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo,		2004 Form 10-K, Ex 10(d)(1)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Kingsport Power Company and Wheeling Power Company.	
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f). 2003 Form 10-K, Ex 10(e)
10(f)(2)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004.
10(g)	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested).	1994 Form 10-K, Ex 10(l)(2).
†10(h)	AEP System Senior Officer Annual Incentive Compensation Plan.	AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(i)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
†10(i)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(i)(1)(B)
*†10(i)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 19, 2005.	
†10(i)(3)	Umbrella Trust for Executives.	AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(j)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(j)(1).
†10(j)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.
†10(j)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(j)(3).
*†10(j)(4)	Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English	AEP Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525,
†10(k)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
†10(k)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(k)(2).
†10(l)	AEP Change In Control Agreement, effective January 1, 2006.	Form 8-K, Ex 1, dated January 3, 2006.
†10(m)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 8-K, Ex. 10.1, dated April 26, 2005..
†10(m)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended	AEP Form 10-Q, Ex. 10(c), dated November 5, 2004, File No. 1-3525.
†10(m)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(n)(1)	Central and South West System Special Executive	CSW 1998 Form 10-K, Ex 18, File No. 1-1443.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Retirement Plan as amended and restated effective July 1, 1997.	
†10(n)(2)	Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.	2003 Form 10-K, Ex 10(o)(3).
†10(o)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005.	2003 Form 10-K, Ex 10(p)(1); Form 10-Q, Ex. 10(b), June 30, 2005.
†10(p)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(q).
†10(q)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K, Ex 10(r).
†10(r)	Base Salaries for Named Executive Officers	Form 8-K, Item 1.01, dated December 13, 2005
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of OPCo.	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: PSO‡	***File No. 0-343***	
3(a)	Restated Certificate of Incorporation of PSO.	CSW 1996 Form U5S, Ex B-3.1, File No. 1-1443.
3(b)	By-Laws of PSO (amended as of June 28, 2000).	2002 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Exs 4(a)(b); Registration Statement No. 333-114665, Ex 4(c).
4(b)	Fourth Supplemental Indenture, dated as of June 7, 2004 between PSO and The Bank of New York, as Trustee, establishing terms of the 4.70% Senior Notes, Series D, due 2009	Form 8-K, Ex 4(a), dated June 7, 2004
4(c)	Fifth Supplemental Indenture, dated as of May 20, 2005 between PSO and The Bank of New York, as Trustee, establishing t erms of the 4.70% Senior Notes, Series E, due 2011	Form 8-K, Ex 4(a), dated June 30, 2005
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: SWEPCo‡	***File No. 1-3146***	
3(a)	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation.	Form 10-Q, Ex 3.4, March 31, 1997.
3(b)	By-Laws of SWEPCo (amended as of April 27, 2000).	Form 10-Q, Ex 3.3, March 31, 2000.
4(a)	Indenture, dated February 1, 1940, between SWEPCo and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.04; Registration Statement No. 2-61943, Ex 2.02; Registration Statement No. 2-66033, Ex 2.02; Registration Statement No. 2-71126, Ex 2.02; Registration Statement No. 2-77165, Ex 2.02; Form U-1 No. 70-7121, Ex 4; Form U-1 No. 70-7233, Ex 3; Form U-1 No. 70-7676, Ex 3; Form U-1 No. 70-7934, Ex 10; Form U-1 No. 72-8041, Ex 10(b); Form U-1 No. 70-8041, Ex 10(c); Form U-1 No. 70-8239, Ex 10(a).
4(b)	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo: (1) Subordinated Indenture, dated as of September 1, 2003, between SWEPCo and the Bank of New York, as Trustee. (2) Amended and Restated Trust Agreement of SWEPCo Capital Trust I, dated as of September 1, 2003, among SWEPCo, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustees. (3) Guarantee Agreement, dated as of September 1, 2003, delivered by SWEPCo for the benefit of the holders of SWEPCo Capital Trust I's Preferred Securities. (4) First Supplemental Indenture dated as of October 1, 2003, providing for the issuance of Series B Junior Subordinated Debentures between SWEPCo, as Issuer and the Bank of New York, as Trustee (5) Agreement as to Expenses and Liabilities, dated as of October 1, 2003 between SWEPCo and SWEPCo Capital Trust I (included in Item (4) above as Ex 4(f)(i)(A).	2003 Form 10-K, Ex 4(b).
4(c)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-87834, Ex 4(a)(b); Registration Statement No. 333-600632, Ex 4(b); Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b).
4(e)	Fourth Supplemental Indenture, dated as of June 28, 2005 between SWEPCO and The Bank of New York, as	Form 8-K, Ex 4(a), dated June 30, 2005

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Trustee, establishing terms of 4.90% Senior Notes, Series D, due 2015.	
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of SWEPCo.	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: TCC‡ File No. 0-346		
3(a)	Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation.	Form 10-Q, Ex 3.1, March 31, 1997.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TCC dated December 18, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TCC (amended as of April 19, 2000).	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of November 15, 1999, between TCC and The Bank of New York, as Trustee, as amended and supplemented.	2000 Form 10-K, Ex 4(c)(d)(e).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(e).
4(d)	Second Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 6.65% Senior Notes, Series B, due 2033 and 6.65% Senior Notes, Series E, due 2033.	2003 Form 10-K, Ex 4(f).
4(e)	Third Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 3.00% Senior Notes, Series C, due 2005 and 3.00% Senior Notes, Series F, due 2005.	2003 Form 10-K, Ex 4(g).
4(f)	Fourth Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee,	2003 Form 10-K, Ex 4(h).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	establishing the terms of Floating Rate Notes, Series A, due 2005 and Floating Rate Notes, Series B, due 2005.	
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Purchase and Sale Agreement, dated as of September 3, 2004, by and between TCC and City of San Antonio (acting by and through the City Public Service Board of San Antonio) and Texas Genco, L.P.	Form 10-Q, Ex. 10(a), September 30, 2004.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the TCC 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
21	List of subsidiaries of TCC.	AEP 2005 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: TNC‡ File No. 0-340		
3(a)	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation.	1996 Form 10-K, Ex 3.5.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TNC dated December 17, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TNC (amended as of May 1, 2000).	Form 10-Q, Ex 3.4, March 31, 2000.
4(a)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(b).
4(b)	First Supplemental Indenture, dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(c).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the TNC 2005 Annual Report (for the fiscal year ended December 31, 2005) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

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2005 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Financial Discussion and Analysis

AEP
AMERICAN®
ELECTRIC
POWER

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO ANNUAL REPORTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
APB 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
EPACT	Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.

I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 115	Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities."

SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including implementation of EPACT and membership in and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP COMMON STOCK AND DIVIDEND INFORMATION

The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2005	$ 40.80	$ 35.57	$ 37.09	$ 0.37
September 30, 2005	39.84	36.34	39.70	0.35
June 30, 2005	37.00	33.79	36.87	0.35
March 31, 2005	36.34	32.25	34.06	0.35
December 31, 2004	35.53	31.25	34.34	0.35
September 30, 2004	33.21	30.27	31.96	0.35
June 30, 2004	33.58	28.50	32.00	0.35
March 31, 2004	35.10	30.29	32.92	0.35

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2005, AEP had approximately 120,000 registered shareholders.

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2005	2004	2003	2002	2001
			(in millions)		
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 12,111	$ 14,245	$ 14,833	$ 13,641	$ 13,044
Operating Income	$ 1,927	$ 1,983	$ 1,743	$ 1,930	$ 2,289
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,029	$ 1,127	$ 522	$ 485	$ 960
Discontinued Operations, Net of Tax	27	83	(605)	(654)	41
Extraordinary Loss, Net of Tax	(225)	(121)	-	-	(48)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	193	(350)	18
Net Income (Loss)	$ 814	$ 1,089	$ 110	$ (519)	$ 971
BALANCE SHEETS DATA			(in millions)		
Property, Plant and Equipment	$ 39,121	$ 37,294	$ 36,031	$ 34,132	$ 32,993
Accumulated Depreciation and Amortization	14,837	14,493	14,014	13,544	12,655
Net Property, Plant and Equipment	$ 24,284	$ 22,801	$ 22,017	$ 20,588	$ 20,338
Total Assets	$ 36,172	$ 34,636	$ 36,736	$ 36,003	$ 40,452
Common Shareholders' Equity	$ 9,088	$ 8,515	$ 7,874	$ 7,064	$ 8,229
Cumulative Preferred Stocks of Subsidiaries (a) (d)	$ 61	$ 127	$ 137	$ 145	$ 156
Trust Preferred Securities (b)	$ -	$ -	$ -	$ 321	$ 321
Long-term Debt (a) (b)	$ 12,226	$ 12,287	$ 14,101	$ 10,190	$ 9,409
Obligations Under Capital Leases (a)	$ 251	$ 243	$ 182	$ 228	$ 451
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.64	$ 2.85	$ 1.35	$ 1.46	$ 2.98
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)	(1.97)	0.13
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-	-	(0.16)
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51	(1.06)	0.06
Basic Earnings (Loss) Per Share	$ 2.09	$ 2.75	$ 0.29	$ (1.57)	$ 3.01
Weighted Average Number of Basic Shares Outstanding (in millions)	390	396	385	332	322
Market Price Range:					
High	$ 40.80	$ 35.53	$ 31.51	$ 48.80	$ 51.20
Low	$ 32.25	$ 28.50	$ 19.01	$ 15.10	$ 39.25
Year-end Market Price	$ 37.09	$ 34.34	$ 30.51	$ 27.33	$ 43.53
Cash Dividends Paid per Common Share	$ 1.42	$ 1.40	$ 1.65	$ 2.40	$ 2.40
Dividend Payout Ratio (c)	67.9%	50.9%	569.0%	(152.9)%	79.7%
Book Value per Share	$ 23.08	$ 21.51	$ 19.93	$ 20.85	$ 25.54

(a) Including portion due within one year.

(b) See "Trust Preferred Securities" section of Note 17.

(c) Based on AEP historical dividend rate.

(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption, which were classified in 2004 as Current Liabilities because the shares were redeemed in January 2005.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the U.S. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We have an extensive portfolio of assets including:

- More than 36,000 megawatts of generating capacity as of December 31, 2005, one of the largest complements of generation in the U.S., the majority of which provides us a significant cost advantage in many of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,026 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 205,483 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (more than 7,000 railcars, 2,300 barges, 53 towboats and one active coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

BUSINESS STRATEGY

Our mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to focus on our core utility business operations. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. Our plan entails designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary, our business strategy calls for us to:

- Respect our people and give them the opportunity to be as successful as they can be.
- Meet the energy needs of our customers in ways that improve their quality of life and protect the environment today and for generations to come.
- Improve the environmental and safety performance of our generating fleet, and grow that fleet.
- Set the standards for safety, efficiency and reliability in our electric transmission and distribution systems.
- Nurture strong and productive relationships with public officials and regulators.
- Provide leadership, integrity and compassion as a corporate citizen to every community we serve.

OUTLOOK FOR 2006

We remain focused on the fundamental earning power of our utilities, and we are committed to maintaining the strength of our balance sheet. To achieve our goals we expect to:

- Obtain permits for our proposed IGCC plants and move forward with the engineering and design for one or more IGCC plants.
- Determine the appropriate generation source for additions to our western fleet.
- Begin preliminary steps to add to our transmission assets to ensure competitive energy prices for our customers in and around congested areas.
- Obtain favorable resolutions to our numerous pending rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

There are, nevertheless, certain risks and challenges including:

- Regulatory activity in Texas, Ohio, Virginia, West Virginia, Indiana and with the FERC.
- Fuel cost volatility and fuel cost recovery, including related transportation issues.
- Financing and recovering the cost of capital expenditures, including environmental and new technology.
- Wholesale market volatility.
- Plant availability.
- Weather.

Regulatory Activity

In 2005, we filed base rate cases in West Virginia and Kentucky requesting revenue increases totaling approximately $248 million, made a filing in Virginia requesting recovery of $62 million in environmental and reliability costs, filed a depreciation study in Indiana to reduce our book depreciation rates predominantly due to a 20–year nuclear license extension at the Cook Plant, filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant and submitted our $2.4 billion stranded cost recovery filing in Texas. In February 2006, we executed and submitted a settlement agreement in the Kentucky proceeding and are awaiting a final order. In February 2006, we also received a final order in the Texas proceedings and now expect to recover stranded costs of approximately $1.3 billion. Our other outstanding filings are progressing and we expect final orders throughout the first half of 2006.

The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005. Jurisdiction over certain holding company-related activities has been transferred from the SEC to the FERC. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company.

Fuel Costs

Market prices for coal, natural gas and oil continued to increase in 2005 following dramatic increases in 2004. These increasing fuel costs are the result of increasing worldwide demand, supply interruptions and uncertainty, anticipation and ultimate promulgation of clean air rules, transportation constraints and other market factors. We manage price and performance risk through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 50% of our fuel costs in our various jurisdictions. Additionally, about 20% of our fuel is used for off-system sales where prices for our power should allow us to recover our cost of fuel. Accordingly, we should recover approximately 70% of fuel cost increases. The remaining 30% of our fuel costs relate primarily to Ohio and Indiana customers, where we do not have fuel cost recovery mechanisms that will become either active in 2006 or such mechanisms are currently capped. Such percentages are subject to change over time based on fuel cost impacts, fuel caps and freezes and changes to the recovery mechanisms at jurisdictions in our individual operating companies. In West Virginia, we were granted permission to begin deferral accounting for over– or under–recovery of fuel and related costs effective July 1, 2006. In addition, our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans. While these items should help to offset some of the negative impact on our gross margins, we expect an additional eleven to thirteen percent increase in coal costs in 2006.

Capital Expenditures

Our current projections call for capital expenditures of approximately $10.9 billion from 2006-2008, $4.9 billion of which represents committed construction expenditures and $6.0 billion of which represents discretionary expenditures predicated on rate recovery and/or cash generated from operations.

For 2006, $3.7 billion in construction expenditures, excluding allowances for funds used during construction, are forecasted as follows:

		(in millions)
Environmental	$	1,531
Distribution		790
Transmission		505
Generation		476
New Generation		191
Nuclear		111
Corporate		110

Off-System Sales

In 2006, we expect an approximate 25% decline in gross margins from off-system sales. This decline is primarily due to the sale of TCC generation in 2004 and 2005, increases in planned outages to facilitate our capital improvements and increased demand for electricity from our native load retail customers, all of which reduces the amount of power available for off-system sales.

2005 RESULTS

Our Utility Operations, the core of our business, had a year of continued improvement and favorable operating conditions in 2005. Our results for the year reflect the increased demand from our industrial customers and sales growth in the residential and commercial classes. These are solid indicators that the economic recovery is reaching all sectors. Favorable weather during summer and fall also increased our revenues above expected norms.

Our forecasts indicate that the obligated capacity requirements to meet the growing electricity needs of customers in our eastern seven states will soon exceed the capabilities of our existing fleet of power plants. Our strategy for meeting this growth in demand includes construction of new plants and acquisitions of existing plants. In 2005, we acquired two generating assets, the Waterford Plant and the Ceredo Generating Station, for approximately $320 million. These two assets added 1,326 MW of generating capacity to our eastern fleet.

During 2005, we also announced more than 20 new or renewed wholesale power supply agreements commencing in 2006 or 2007 with various municipalities throughout our service territory. These agreements allow us to remain one of the largest providers of wholesale energy to municipals and cooperatives and demonstrate our commitment to traditional wholesale customers. In 2006, we expect to provide approximately 3,500 MW of full or partial requirement power to 55 municipal utilities and 25 electric cooperatives.

During 2005, we further stabilized our financial strength by:

- Completing asset divestitures of our remaining gas pipeline and storage assets and nuclear generation in Texas resulting in proceeds of approximately $1.6 billion.
- Using the cash flows from our operations to fully fund our qualified pension plans, which also improved our debt to capital ratio to 57.2% at December 31, 2005.
- Receiving upgraded credit ratings from Moody's Investors Service for AEP's short-term and long-term debt.

While we were successful in 2005 in reducing our debt to total capital ratio from 59.1% to 57.2%, we have significant capital expenditures projected for the near-term. Through a combination of cash generated from operations, increased rates as requested in our pending regulatory proceedings and a portion of the Texas stranded cost securitization proceeds, we expect to maintain the strength of our balance sheet and fund our capital expenditure program without material additional leverage.

RESULTS OF OPERATIONS

Segments

In 2005, AEP's principal operating business segments and their major activities were:

- Utility Operations:
  - Generation of electricity for sale to U.S. retail and wholesale customers
  - Electricity transmission and distribution in the U.S.
- Investments – Other:
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply-related businesses

Our consolidated Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes for the years ended December 31, 2005, 2004 and 2003 were as follows (Earnings and Weighted Average Basic Shares Outstanding in millions):

	2005		2004		2003	
	Earnings	**EPS (c)**	**Earnings**	**EPS (c)**	**Earnings**	**EPS (c)**
Utility Operations	$ 1,020	$ 2.61	$ 1,175	$ 2.97	$ 1,223	$ 3.18
Investments – Other	93	0.24	74	0.19	(282)	(0.73)
All Other (a)	(53)	(0.13)	(71)	(0.18)	(129)	(0.34)
Investments – Gas Operations (b)	(31)	(0.08)	(51)	(0.13)	(290)	(0.76)
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,029	$ 2.64	$ 1,127	$ 2.85	$ 522	$ 1.35
Weighted Average Basic Shares Outstanding		390		396		385

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.
(b) We sold our remaining gas pipeline and storage assets in 2005.
(c) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes in 2005 decreased $98 million compared to 2004 primarily due to gains on sales of equity investments in 2004 and a decrease in recorded stranded generation carrying costs income in 2005, as a result of the PUCT decisions related to TCC's True-up Proceeding.

Average basic shares outstanding decreased to 390 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program executed in 2005.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes in 2004 increased $605 million compared to 2003 due to recorded stranded generation carrying costs income at TCC for the years 2002-2004, lower impairments and increased gains realized on the sales of assets. These increases were offset, in part, by decreased margins due to the divestiture of Texas generation assets, the loss of the capacity auction true-up revenues in Texas and higher operations and maintenance expense.

Average basic shares outstanding increased to 396 million in 2004 from 385 million in 2003 due to a common stock issuance in 2003 and common shares issued related to our incentive compensation plans.

Our results of operations are discussed below according to our operating segments.

Utility Operations

Our Utility Operations include primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of our Utility Operations segment results on a gross margin basis is most appropriate. Gross margins represent utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	2005	2004	2003
		(in millions)	
Revenues	$ 11,396	$ 10,769	$ 11,160
Fuel and Purchased Power	4,290	3,704	3,844
Gross Margin	7,106	7,065	7,316
Depreciation and Amortization	1,285	1,256	1,250
Other Operating Expenses	3,833	3,778	3,591
Operating Income	1,988	2,031	2,475
Other Income (Expense), Net	103	330	31
Interest Charges and Preferred Stock Dividend Requirements	595	627	673
Income Tax Expense	476	559	610
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,020	$ 1,175	$ 1,223

Summary of Selected Sales and Weather Data
For Utility Operations
For the Years Ended December 31, 2005, 2004 and 2003

	2005	2004	2003
Energy Summary		(in millions of KWH)	
Retail:			
Residential	48,720	45,770	45,308
Commercial	38,605	37,203	36,798
Industrial	53,217	51,484	49,446
Miscellaneous	2,593	3,099	3,026
Subtotal	143,135	137,556	134,578
Texas Retail and Other	615	1,065	2,896
Total	143,750	138,621	137,474
Wholesale	47,784	57,409	47,163
Texas Wires Delivery	26,525	25,581	25,814

	2005	2004	2003
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,130	2,992	3,219
Normal – Heating (b)	3,088	3,086	3,075
Actual – Cooling (c)	1,152	877	756
Normal – Cooling (b)	969	974	976
Western Region (d)			
Actual – Heating (a)	1,377	1,382	1,554
Normal – Heating (b)	1,615	1,624	1,622
Actual – Cooling (c)	2,386	2,006	2,144
Normal – Cooling (b)	2,150	2,149	2,138

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the 30-year average of degree days.
(c) Eastern Region and Western Region cooling days are calculated on a 65 degree temperature base.
(d) Western Region statistics represent PSO/SWEPCo customer base only.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 1,175
Changes in Gross Margin:		
Retail Margins	67	
Texas Supply	(141)	
Off-system Sales	158	
Transmission Revenues	(57)	
Other Revenues	14	
Total Change in Gross Margin		41
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(95)	
Asset Impairments and Other Related Charges	(39)	
Gain on Sales of Assets, Net	116	
Depreciation and Amortization	(29)	
Taxes Other Than Income Taxes	(37)	
Other Income (Expense), Net	(227)	
Interest and Other Charges	32	
Total Change in Operating Expenses and Other		(279)
Income Tax Expense		83
Year Ended December 31, 2005		$ 1,020

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $155 million to $1,020 million in 2005. Key drivers of the decrease included a $279 million increase in Operating Expenses and Other, offset in part by a $41 million increase in Gross Margin and an $83 million decrease in Income Tax Expense.

The major components of the net increase in Gross Margin were as follows:

- The increase in Retail Margins from our utility segment over the prior year was due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. The higher usage was primarily weather-related as cooling degree days increased 31% and 19% for the East and West, respectively. This load growth was partially offset by higher delivered fuel costs of approximately $129 million, of which the majority relates to our East companies with inactive fuel clauses.
- Our Texas Supply business experienced a $141 million decrease in gross margin principally due to the sale of almost all of our Texas generation assets to support Texas stranded cost recovery.
- Margins from Off-system Sales for 2005 were $158 million higher than in 2004 due to favorable price margins.
- Transmission Revenues decreased $57 million primarily due to the loss of through-and-out rates as mandated by the FERC.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses increased $95 million due to an $87 million increase in generation expense related to strong retail and wholesale sales and capacity requirements and plant maintenance in 2005 and PJM expenses of $30 million. Additionally, distribution maintenance expense increased $91 million from tree trimming and reliability work. These increases were partially offset by reduced administrative and general expenses of $90 million.
- 2005 included a $39 million impairment related to the retirement of two units at CSPCo's Conesville Plant effective December 29, 2005.
- Gain on Sales of Assets, Net increased $116 million resulting from the receipt of revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase and sale agreement from the sale of our REPs in 2002. Agreement was reached with Centrica in March 2005 resolving disputes back to 2002 on how such amounts were calculated.
- Depreciation and Amortization expense increased $29 million primarily due to a higher depreciable asset base.
- Taxes Other Than Income Taxes increased $37 million due to increased property tax values and assessments and higher state excise taxes due to the increase in taxable KWH sales.
- Other Income (Expense), Net decreased $227 million primarily due to the following:
    - A $321 million decrease related to carrying costs recorded by TCC on its net stranded generation costs and its capacity auction true-up asset. In 2004, TCC booked $302 million of carrying costs income related to 2002 – 2004. Upon receipt of the final order in February 2006 in TCC's True-up Proceeding, we determined that adjustments to those carrying costs were required, resulting in carrying costs expense of $19 million in 2005 for TCC.
    - A $56 million increase related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
    - A $20 million increase related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.
    - A $14 million increase related to the establishment of regulatory assets for carrying costs on environmental and system reliability capital expenditures for APCo.
- Interest and Other Charges decreased $32 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates and the retirement of debt in 2004 and 2005.
- Income Tax Expense decreased $83 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ 1,223
Changes in Gross Margin:		
Retail Margins	52	
Texas Supply	(105)	
Wholesale Capacity Auction True-up Revenues	(215)	
Off-System Sales	10	
Other Revenues	7	
Total Change in Gross Margin		(251)
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(171)	
Asset Impairments and Other Related Charges	10	
Depreciation and Amortization	(6)	
Taxes Other Than Income Taxes	(26)	
Carrying Costs	302	
Other Income (Expense), Net	(3)	
Interest and Other Charges	46	
Total Change in Operating Expenses and Other		152
Income Tax Expense		51
Year Ended December 31, 2004		$ 1,175

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $48 million to $1,175 million in 2004. Key drivers of the decrease include a $251 million decrease in Gross Margin, offset in part by a $152 million decrease in Operating Expenses and Other and a $51 million decrease in Income Tax Expense.

The major components of the net decrease in Gross Margin were as follows:

- The increase in Retail Margins from our utility segment over the prior year was due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. Commercial and industrial demand also increased, resulting from the economic recovery in our regions. Milder weather during the summer months of 2004 partially offset these favorable results.
- Our Texas Supply business experienced a $105 million decrease in gross margin principally due to the partial divestiture of a portion of TCC's generation assets to support Texas stranded cost recovery. This resulted in higher purchased power costs to fulfill contractual commitments.
- Beginning in 2004, the wholesale capacity auction true-up ceased per the Texas Restructuring Legislation. Related revenues were no longer recognized, resulting in $215 million of lower regulatory asset deferrals in 2004. For 2003, we recognized the revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
- Margins from Off-system Sales for 2004 were $10 million higher than in 2003 due to favorable optimization activity, somewhat offset by lower volumes.

Utility Operating Expenses and Other changed between the years as follows:

- Maintenance and Other Operation expenses increased $171 million due to a $76 million increase in generation expense primarily due to an increase in maintenance outage weeks in 2004 as compared to 2003 and increases in related removal costs and PJM expenses. Additionally, distribution maintenance expense increased $54 million from system improvement and reliability work and damage repair resulting primarily from major ice storms in our Ohio service territory during December 2004. Other increases of $81 million include ERCOT and transmission cost of service adjustments in 2004 and increased employee benefits, insurance, and other administrative and general expenses magnified by favorable adjustments in 2003. These increases were offset, in part, by $40 million due to the conclusion in 2003 of the amortization of our deferred Cook Plant restart expenses.
- 2003 included a $10 million impairment at Blackhawk Coal Company, a wholly-owned subsidiary of I&M, which holds western coal reserves.
- Taxes Other Than Income Taxes increased $26 million due to increased property tax values and assessments, higher state excise taxes due to the increase in taxable KWH sales, and favorable prior year franchise tax adjustments.
- Carrying Costs of $302 million represent TCC's debt component of the carrying costs accrued on its net stranded generation costs and its capacity auction true-up asset.
- Interest Charges decreased $46 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates.
- Income Tax expense decreased $51 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

Investments – Other

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes from our Investments – Other segment increased from $74 million in 2004 to $93 million in 2005. The increase was partially due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges causing a 45% increase in ton mile freight rates between 2004 and 2005 and various tax adjustments.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes from our Investments – Other segment increased from a loss of $282 million in 2003 to income of $74 million in 2004. The increase was primarily due to gains on sales of assets and equity investments in 2004 of $95 million and impairments of $257 million recorded in 2003.

Other

Parent

2005 Compared to 2004

The parent company's loss decreased $18 million from 2004 primarily due to lower interest expense related to the redemption of $550 million senior unsecured notes in April 2005 and a $20 million provision for penalties in 2004. The decrease was partially offset by lower interest income and guarantee fees related to the repayment of intercompany debt associated with the HPL and UK sales.

2004 Compared to 2003

The parent company's 2004 loss decreased $58 million from 2003 due to a $40 million provision for penalties booked in 2003 compared to $20 million in 2004, a $12 million decrease in expenses primarily resulting from lower insurance premiums and lower general advertisement expenses in 2004 and a $20 million decrease in income taxes related to federal tax accrual adjustments. The decrease in loss was offset by lower interest income of $9 million in the current period due to lower cash balances, along with higher interest rates on invested funds in 2003. Additionally, parent guarantee fee income from subsidiaries was $4 million lower due to the reduction of trading activities. There is no effect on consolidated net income for this item.

Investments – Gas Operations

2005 Compared to 2004

The $31 million Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes compares with a $51 million loss recorded for 2004. Current year results include only one month of HPL's operations compared to a full year of HPL operations in the prior year due to the sale of HPL in January of 2005. We also resolved a portion of our outstanding Enron litigation in 2005 resulting in a net of tax settlement cost of approximately $28 million.

2004 Compared to 2003

The Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $239 million to $51 million in 2004. The key driver of the decrease was $315 million of impairments recorded in 2003, partially offset by a $103 million decrease in income tax benefit principally related to the impairments.

AEP System Income Taxes

The decrease in income tax expense of $142 million between 2004 and 2005 is primarily due to a decrease in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by the recording of the tax return adjustments.

The increase in income tax expense of $214 million between 2003 and 2004 is primarily due to an increase in pretax book income, offset in part by the recording of the tax return and tax reserve adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2005, we improved our financial condition as a consequence of the following actions and events:

- We completed approximately $2.7 billion of long-term debt redemptions, including optional redemptions and debt maturities;
- AEP was upgraded to Baa2/P-2 by Moody's Investors Service (Moody's) and we maintained stable credit ratings across the AEP System including our rated subsidiaries; and
- We fully funded our defined benefit qualified pension plans, resulting in the elimination of our minimum pension liability for the qualified plans.

Capitalization ($ in millions)

	December 31, 2005		December 31, 2004	
Common Equity	$ 9,088	42.5%	$ 8,515	40.6%
Preferred Stock	61	0.3	61	0.3
Preferred Stock (Subject to Mandatory Redemption)	-	-	66	0.3
Long-term Debt, including amounts due within one year	12,226	57.2	12,287	58.7
Short-term Debt	10	0.0	23	0.1
Total Capitalization	$ 21,385	100.0%	$ 20,952	100.0%

Our common equity increased due to earnings exceeding the amount of dividends paid in 2005 and a $626 million cash contribution to our qualified pension funds, which allowed us to remove the $330 million charge to equity related to underfunded plans.

As a consequence of the capital changes during 2005 noted above, we improved our ratio of debt to total capital from 59.1% to 57.2% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability even for fully funded pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 smoothing deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net of tax accumulated other comprehensive income reduction to common equity. We cannot predict the effects of the final rule or its effective date.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2005, our available liquidity was approximately $3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,000	May 2007
Revolving Credit Facility	1,500	March 2010
Letter of Credit Facility	200	September 2006
Total	2,700	
Cash and Cash Equivalents	401	
Total Liquidity Sources	3,101	
Less: Letters of Credit Drawn on Credit Facility	91	
Net Available Liquidity	$ 3,010	

During the first half of 2006, subject to market conditions, we plan to amend the terms and increase the size of our $1 billion credit facility expiring in May 2007. We may also amend our $1.5 billion credit facility expiring in March 2010. We also plan to terminate our $200 million letter of credit facility upon its expiration in September 2006. In total, we expect to increase our total credit facilities from $2.7 billion to $3.0 billion.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At December 31, 2005, this percentage was 54.2%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2005, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

Our $1 billion revolving credit facility, which matures in May 2007, generally prohibits new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under this facility if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper. Under the $1.5 billion revolving credit facility, which matures in March 2010, we may borrow despite a material adverse change.

Under a regulatory order, AEP's utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At December 31, 2005, all utility subsidiaries were in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2005, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 383 consecutive quarters. The Board of Directors increased the quarterly dividend from $0.35 to $0.37 per share in October 2005. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. In 2005, we announced criteria that will be used to make future dividend recommendations to the Board of Directors.

Credit Ratings

Moody's upgraded AEP's short and long-term debt ratings during 2005. Our current credit ratings are as follows:

	Moody's	S&P	Fitch
AEP Short Term Debt	P-2	A-2	F-2
AEP Senior Unsecured Debt	Baa2	BBB	BBB

If we or any of our rated subsidiaries receive an upgrade from any of the rating agencies listed above, our borrowing costs could decrease. If we receive a downgrade in our credit ratings by one of the rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Our cash flows are a major factor in managing and maintaining our liquidity strength.

	2005	2004	2003
		(in millions)	
Cash and cash equivalents at beginning of period	$ 320	$ 778	$ 1,085
Net Cash Flows From Operating Activities	1,877	2,711	2,500
Net Cash Flows Used For Investing Activities	(1,005)	(329)	(2,298)
Net Cash Flows Used For Financing Activities	(791)	(2,840)	(509)
Net Increase (Decrease) in Cash and Cash Equivalents	81	(458)	(307)
Cash and cash equivalents at end of period	$ 401	$ 320	$ 778

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders.

Operating Activities

	2005	2004	2003
		(in millions)	
Net Income	$ 814	$ 1,089	$ 110
Plus: (Income) Loss From Discontinued Operations	(27)	(83)	605
Income From Continuing Operations	787	1,006	715
Noncash Items Included in Earnings	1,714	1,471	1,939
Changes in Assets and Liabilities	(624)	234	(154)
Net Cash Flows From Operating Activities	$ 1,877	$ 2,711	$ 2,500

The key drivers of the decrease in cash from operations in 2005 are the pension contribution of $626 million and an increase in under-recovered fuel of $239 million.

2005 Operating Cash Flow

Net Cash Flows From Operating Activities were approximately $1.9 billion in 2005. We produced Income from Continuing Operations of $787 million. Income from Continuing Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. We made contributions of $626 million to our pension trusts. Under-recovered fuel costs increased due to the higher cost of fuel, especially natural gas. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking to recover our increased fuel costs. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a $140 million cash increase from Accounts Payable due to higher fuel and allowance acquisition costs not paid at December 31, 2005 and an increase in Customer Deposits of $157 million.

2004 Operating Cash Flow

During 2004, Net Cash Flows From Operating Activities were $2.7 billion consisting of our Income from Continuing Operations of $1 billion and noncash charges of $1.6 billion for depreciation, amortization and deferred taxes. We recorded $302 million in noncash income for carrying costs on Texas stranded cost recovery and recognized an after-tax, noncash extraordinary loss of $121 million to provide for probable disallowances to TCC's stranded generation costs. We realized gains of $157 million on sales of assets, primarily the IPPs and our South Coast equity investment. We made $231 million of contributions to our pension trusts.

Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Changes in working capital items resulted in cash from operations of $430 million predominantly due to increased accrued income taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

2003 Operating Cash Flow

Net Cash Flows From Operating Activities were $2.5 billion in 2003. We produced Income From Continuing Operations of $715 million during the period. Income From Continuing Operations for 2003 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, $193 million for the cumulative effects of accounting changes, and $720 million for impairment losses and other related charges. In addition, there was a current period impact for a net $122 million balance sheet change for risk management contracts that are marked-to-market. These derivative contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The 2003 activity in changes in assets and liabilities relates to a number of items; the most significant of which were:

- Noncash wholesale capacity auction true-up revenues resulting in stranded cost regulatory assets of $218 million, which are not recoverable in cash until the conclusion of TCC's True-up Proceeding.
- Net changes in accounts receivable and accounts payable of $291 million related, in large part, to the settlement of risk management positions during 2002 and payments related to those settlements during 2003. These payments include $90 million in settlement of power and gas transactions to the Williams Companies. The earnings effects of substantially all payments were reflected on a MTM basis in earlier periods.
- Increases in fuel and inventory levels of $52 million resulting primarily from higher procurement prices.
- Reserves for disallowed deferred fuel costs, principally related to Texas, which are a component of our Texas True-up Proceedings.

Investing Activities

	2005	2004	2003
		(in millions)	
Construction Expenditures	$ (2,404)	$ (1,637)	$ (1,322)
Change in Other Temporary Cash Investments, Net	76	32	(91)
Investment in Discontinued Operations, Net	-	(59)	(615)
Purchases of Investment Securities	(8,836)	(1,574)	(1,022)
Sales of Investment Securities	8,934	1,620	736
Acquisitions of Assets	(360)	-	-
Proceeds from Sales of Assets	1,606	1,357	82
Other	(21)	(68)	(66)
Net Cash Flows Used for Investing Activities	$ (1,005)	$ (329)	$ (2,298)

Net Cash Flows Used For Investing Activities were $1.0 billion in 2005 primarily due to Construction Expenditures being partially offset by the proceeds from the sales of HPL and STP. The sales were part of an announced plan to divest noncore investments and assets and a requirement of collecting stranded costs in Texas. Construction Expenditures increased due to our environmental investment plan.

We purchase auction rate securities and variable rate demand notes with cash available for short-term investments. During 2005, we purchased $8.8 billion of investments and received $8.9 billion of proceeds from their sale. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $329 million in 2004. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.6 billion were distributed across our system, of which the most significant expenditures were investments for environmental improvements of $350 million and for a high voltage transmission line of $75 million. During 2004, we sold our U.K. generation, Jefferson Island Storage, LIG and certain IPP and TCC generation assets and used the proceeds from the sales of these assets to reduce debt.

Net Cash Flows Used For Investing Activities were $2.3 billion in 2003 for increased investments in our U.K. operations and environmental and normal capital expenditures.

We forecast $3.7 billion of construction expenditures for 2006. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	2005	2004	2003
		(in millions)	
Issuance of Common Stock	$ 402	$ 17	$ 1,142
Repurchase of Common Stock	(427)	-	-
Issuance/Retirement of Debt, Net	(91)	(2,238)	(743)
Dividends Paid on Common Stock	(553)	(555)	(618)
Other	(122)	(64)	(290)
Net Cash Flows Used for Financing Activities	$ (791)	$ (2,840)	$ (509)

In 2005, we used $791 million of cash to pay dividends, retire preferred stock and reduce debt.

In 2004, we used $2.8 billion of cash to reduce debt and pay common stock dividends. We achieved our goal of reducing debt below 60% of total capitalization by December 31, 2004. The debt reductions were primarily funded by proceeds from our various divestitures in 2004.

Our cash flows used for financing activities were $509 million during 2003. The proceeds from the issuance of common stock were used to reduce outstanding debt and minority interest in a finance subsidiary.

The following financing activities occurred during 2005:

Common Stock:

- In March 2005, we repurchased 12,500,000 shares of common stock for $427 million.
- In August 2005, we issued 8,435,200 shares of common stock to settle part of a forward contract in equity units issued in 2002.
- During 2005, we issued 1,925,485 shares of common stock under our incentive compensation plans and received net proceeds of $57 million.

Debt:

- During 2005, we issued approximately $2.7 billion of long-term debt, including approximately $676 million of pollution control revenue bonds. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions, asset acquisitions and construction programs.
- During 2005, we entered into $1,090 million of interest rate derivatives and unwound $1,365 million of such transactions. The unwinds resulted in a net cash expenditure of $25.5 million. As of December 31, 2005, we had in place interest rate hedge transactions with a notional amount of $125 million in order to hedge a portion of anticipated 2006 issuances.
- At December 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. As of December 31, 2005, we had no commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%.

Our plans for 2006 include the following:

- In February of 2006, APCo issued obligations relating to auction rate pollution control bonds in the amount of $50 million. The new bonds bear interest at a 28-day auction rate. The proceeds from this issuance will contribute to our investment in environmental equipment.
- In 2006, our plan for capital investment will require additional funding from the capital markets.

Off-balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and, in accordance with GAAP, are not required to consolidate these entities. We continue to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate its cash collections.

AEP Credit's sale of receivables agreement expires August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.3 billion as of December 31, 2005.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the future payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Railcars

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms for a maximum of twenty years. We intend to renew the lease for the full twenty years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over time from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 10	$ -	$ -	$ -	$ 10
Interest on Fixed Rate Portion of Long-term Debt (b)	552	939	768	3,982	6,241
Fixed Rate Portion of Long-term Debt (c)	1,131	1,650	1,568	6,017	10,366
Variable Rate Portion of Long-term Debt (d)	22	168	583	1,145	1,918
Capital Lease Obligations (e)	73	113	45	93	324
Noncancelable Operating Leases (e)	313	552	500	2,018	3,383
Fuel Purchase Contracts (f)	2,276	3,092	2,602	6,311	14,281
Energy and Capacity Purchase Contracts (g)	306	431	349	709	1,795
Construction Contracts for Capital Assets (h)	1,267	460	-	-	1,727
Total	$ 5,950	$ 7,405	$ 6,415	$ 20,275	$ 40,045

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 17. Represents principal only excluding interest.
(d) See Note 17. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.10% and 6.35% at December 31, 2005.
(e) See Note 16.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11 to the Consolidated Financial Statements, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. At December 31, 2005, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a) (b)	$ 130	$ -	$ -	$ -	$ 130
Guarantees of the Performance of Outside Parties (b)	8	-	25	105	138
Guarantees of our Performance (c)	1,483	936	688	8	3,115
Transmission Facilities for Third Parties (d)	44	47	-	-	91
Total Commercial Commitments	$ 1,665	$ 983	$ 713	$ 113	$ 3,474

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $130 million with maturities ranging from February 2006 to March 2007. As the parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn.
(b) See "Guarantees of Third-party Obligations" section of Note 8.
(c) We have issued performance guarantees and indemnifications for energy trading, Dow Chemical Company financing, International Marine Terminal Pollution Control Bonds and various sale agreements.
(d) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Other

Texas REPs

As part of the purchase and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2005, upon resolution of various contractual matters with Centrica, we received payments from our share in earnings of $45 million and $70 million for 2003 and 2004, respectively. The 2005 and 2006 payments are contingent on Centrica's future operating results and are capped at $70 million and $20 million for 2005 and 2006, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap. We expect to receive the 2005 payment in March of 2006. (see "Texas REPs" section of Note 10).

SIGNIFICANT FACTORS

AEP Interstate Project

On January 31, 2006, we filed with the FERC and PJM a proposal to build a new 765 kV transmission line stretching from West Virginia to New Jersey. The proposed project, which will span approximately 550 miles, is designed to reduce PJM congestion costs by substantially improving west-east peak transfer capability by approximately 5,000 MW and reducing transmission line losses by up to 280 MW. It will also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is $3 billion, which may be shared with other stakeholders, and the project is subject to regulatory approval and recovery mechanisms. A projected in-service date is 2014, subject to PJM and FERC approval, assuming three years to site and acquire rights-of-way and five years to construct the line. We also filed with the DOE to have the proposed route designated a National Interest Electric

Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.

Texas Regulatory Activity

Texas Restructuring

The stranded cost quantification process in Texas continued in 2005 with TCC filing its True-Up Proceeding in May seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined TCC's stranded costs to be $1.5 billion, including carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. TCC adjusted its December 2005 books to reflect the final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded as a pretax extraordinary loss.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge (CTC). The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an accumulated deferred federal income tax (ADFIT) benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	**$ 1,275**
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	**$ 1,804**

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

If we determine in future securitization and competition transition charge proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. See "Texas Restructuring" section of Note 6 following our financial statements for a discussion of the $200 million difference between the final order and our recorded balance.

Integrated Gasification Combined Cycle (IGCC) Power Plants

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSP. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover, or refund, in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. As of December 31, 2005, we have deferred $7 million of pre-construction IGCC costs for the Ohio companies. These costs primarily relate to an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process.

In January 2006, APCo filed an application with the WVPSC seeking authority to construct a 600MW IGCC electric generating unit in West Virginia. If built, the unit would be located next to APCo's Mountaineer Plant.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans or Pension Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, we have entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic cost for our Pension Plans and Postretirement Plans:

	2005	2004
	(in millions)	
Net Periodic Cost:		
Pension Plans	$ 61	$ 40
Postretirement Plans	109	141
Assumed Rate of Return:		
Pension Plans	8.75%	8.75%
Postretirement Plans	8.37%	8.35%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return, for the period ended December 2005, of approximately 10%. We anticipate that the investment managers we employ for the Plans will generate long-term returns averaging 8.50%.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension		Other Postretirement Benefit Plans		
	2005 Actual Asset Allocation	2006 Target Asset Allocation	2005 Actual Asset Allocation	2006 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	66%	70%	68%	66%	10.00%
Fixed Income	25%	28%	30%	31%	5.25%
Cash and Cash Equivalents	9%	2%	2%	3%	3.50%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. Because we made a $320 million discretionary contribution to the Qualified Plans at the end of 2005, the actual asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006. We believe that 8.50% is a reasonable long-term rate of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 7.76% and 12.90% for the twelve months ended December 31, 2005 and 2004, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2005, we had cumulative losses of approximately $37 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2005 under this method was 5.50% for the Pension Plans and 5.65% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Plans' assets of 8.50%, a discount rate of 5.50% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $73 million, $76 million and $56 million in 2006, 2007 and 2008, respectively. We estimate Postretirement Plan costs will approximate $99 million, $102 million and $97 million in 2006, 2007 and 2008, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 0.5% basis point change to selective actuarial assumptions are in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Management's Financial Discussion and Analysis of Results of Operations.

The value of our Pension Plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004 primarily due to discretionary contributions to the Qualified Plans. The Qualified Plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits). The value of our Postretirement Plans' assets increased to $1.2 billion at December 31, 2005 from $1.1 billion at December 31, 2004. The Postretirement Plans paid $118 million in benefits to plan participants during 2005.

For our pension plans, the accumulated benefit obligation in excess of plan assets was $81 million and $474 million at December 31, 2005 and 2004, respectively. While our non-qualified pension plans are unfunded, our qualified pension plans are fully funded as of December 31, 2005.

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

We made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet our goal of fully funding all Qualified Plans by the end of 2005.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that the defined benefit pension plans we sponsor and maintain are in compliance with the applicable requirements of such laws.

Litigation

In the ordinary course of business, AEP and its subsidiaries are involved in a substantial amount of employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry and Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect the results of operations of AEP and its subsidiaries.

See discussion of the Environmental Litigation within "Significant Factors - Environmental Matters."

Environmental Matters

We have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants; and
- Possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality, and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA is currently reconsidering certain aspects of the final CAIR, and the rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x

emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program has encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the "Regional Haze" program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above will require us to make significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Our estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

We installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at our eastern power plants over the past several years to comply with NO_x requirements in various SIPs. Additional NO_x requirements associated with CAIR and CAMR will result in additional investments between 2006 and 2010, estimated to be $191 million, including completion of SCRs on an additional 1900 MW of capacity.

We are complying with Acid Rain Program SO_2 requirements by installing scrubbers, other controls, and using alternate fuels. We also use SO_2 allowances we receive through Acid Rain Program allocations, purchase at the annual Federal EPA auction, and purchase in the market. Decreasing allowance allocations, our diminishing SO_2 allowance bank, and increasing allowance costs will require us to install additional controls on our power plants. In addition, under CAIR and CAMR we will be required to install additional controls by 2010. We plan to install by 2010 additional scrubbers on 8,700 MW to comply with current, CAIR and CAMR requirements. From 2006 to 2010, we estimate that the additional investment in scrubbers will be approximately $2.8 billion. We will also incur additional operation and maintenance expenses during 2006 and subsequent years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, we expect to incur additional costs for pollution control technology retrofits between 2011 and 2020 of approximately $1 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on our units; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Clean Water Act Regulations

In July 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. Any capital costs incurred to meet these standards will likely be incurred between 2008 and 2010. We are required to undertake site-specific studies, and we may propose site-specific compliance or mitigation measures that could significantly change this estimate. These studies are currently underway, and the rule has been challenged in the courts.

Potential Regulation of CO_2 Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in November 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none has passed either house of Congress.

The Federal EPA has stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. While mandatory requirements to reduce CO_2 emissions at our power plants do not appear to be imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed against other nonaffiliated utilities in 1999 and 2000. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

Courts that have considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, have reached different conclusions. Similarly, courts that have considered whether the activities at issue increased emissions from the power plants have reached different results. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the court. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we are managing other environmental concerns that we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and
- changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

Management has discussed the development and selection of its critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee has reviewed the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

The sections that follow present information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required - Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not yet been made.

Assumptions and Approach Used - When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We review the probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used – A change in the above assumptions may result in a material impact on our results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required – We recognize and record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is also estimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Unbilled electric utility revenues included in Revenue were $28 million, $22 million and $13 million for the years ended December 31, 2005, 2004 and 2003, respectively. Accrued Unbilled Revenues on the Balance Sheets were $374 million and $665 million as of December 31, 2005 and 2004, respectively.

Assumptions and Approach Used – The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation determines factors that limit the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are then statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

In addition, an annual comparison to a load research estimate is performed for the AEP East companies, KGPCo and WPCo. The annual load research study, based on a sample of accounts, is an additional verification of the unbilled estimate. The unbilled estimate is adjusted annually, if necessary, for significant differences from the load research estimate.

Effect if Different Assumptions Used – Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required – Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used – We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used – There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required – In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," long-lived assets are evaluated as necessary for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. These evaluations of long-lived assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For nonregulated assets, an impairment charge would be recorded as a charge against earnings.

Assumptions and Approach Use - The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales, or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used – In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 10 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We have been divesting certain noncore assets and their sales values can vary from the recorded fair value as described in Note 10 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required - We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, "Employers' Accounting For Pensions" and SFAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions", respectively. See Note 11 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by our actuaries and us. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used - The critical assumptions used in developing the required estimates include the following key factors:

- discount rate
- expected return on plan assets
- health care cost trend rates
- rate of compensation increases

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used - The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2005 Benefit Obligations:				
Discount Rate	$ (198)	$ 207	$ (116)	$ 124
Salary Scale	30	(30)	4	(4)
Cash Balance Crediting Rate	(16)	17	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	112	(106)
Effect on 2005 Periodic Cost:				
Discount Rate	(10)	10	(10)	10
Salary Scale	6	(5)	1	(1)
Cash Balance Crediting Rate	3	(2)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(17)
Expected Return on Assets	(18)	18	(5)	5

New Accounting Pronouncements

In December 2004, the FASB issued SFAS 123R "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R. We implemented SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

We adopted FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47) during the fourth quarter of 2005. We completed a review of our FIN 47 conditional asset retirement obligations and concluded that we have legal liabilities for asbestos removal and disposal in general building and generating plants. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to a regulatory liability. We recorded an unfavorable cumulative effect of $26 million ($17 million net of tax) for our non-regulated operations related to asbestos removal in the Utility Operations segment.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty" focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29 "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Investment – Gas Operations segment continues to hold forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives with some physical contracts, which will gradually liquidate and completely expire in 2011. Our risk objective is to keep these positions risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas, coal, and emissions and to a lesser degree other commodities. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and risk management staff. When risk management activities exceed certain predetermined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

We have established policies and procedures that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other senior financial and operating managers.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value included in our balance sheet as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet December 31, 2005 (in millions)

	Utility Operations	Investments - Gas Operations	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 705	$ 210	$ 915	$ 11	$ 926
Noncurrent Assets	593	291	884	2	886
Total Assets	1,298	501	1,799	13	1,812
Current Liabilities	(661)	(223)	(884)	(22)	(906)
Noncurrent Liabilities	(422)	(297)	(719)	(4)	(723)
Total Liabilities	(1,083)	(520)	(1,603)	(26)	(1,629)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 215	$ (19)	$ 196	$ (13)	$ 183

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	$ 265
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(81)	(21)	12	(90)
Fair Value of New Contracts at Inception When Entered During the Period (a)	4	-	-	4
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(6)	-	-	(6)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	19	2	-	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2	-	-	2
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ (19)	$ -	196
Net Cash Flow and Fair Value Hedge Contracts				(13)
Ending Net Risk Management Assets at December 31, 2005				$ 183

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2005
(in millions)

	2006	2007	2008	2009	2010	After 2010	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 42	$ 8	$ 5	$ -	$ -	$ -	$ 55
Prices Provided by Other External Sources – OTC Broker Quotes (a)	56	68	51	26	-	-	201
Prices Based on Models and Other Valuation Methods (b)	(54)	(22)	(11)	12	30	4	(41)
Total	$ 44	$ 54	$ 45	$ 38	$ 30	$ 4	$ 215
Investments – Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (15)	$ 11	$ -	$ -	$ -	$ -	$ (4)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	5	(8)	-	-	-	-	(3)
Prices Based on Models and Other Valuation Methods (b)	(3)	(1)	(2)	(4)	(3)	1	(12)
Total	$ (13)	$ 2	$ (2)	$ (4)	$ (3)	$ 1	$ (19)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ 27	$ 19	$ 5	$ -	$ -	$ -	$ 51
Prices Provided by Other External Sources – OTC Broker Quotes (a)	61	60	51	26	-	-	198
Prices Based on Models and Other Valuation Methods (b)	(57)	(23)	(13)	8	27	5	(53)
Total	$ 31	$ 56	$ 43	$ 34	$ 27	$ 5	$ 196

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is in the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.

The determination of the point at which a market is no longer liquid for placing it in the Modeled category in the preceding table varies by market. The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of December 31, 2005

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	24
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	48
	Physical Forwards	AEP West	48
	Physical Forwards	West Coast	48
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	36
Coal	Physical Forwards	PRB, NYMEX, CSX	36

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Consolidated Balance Sheets

We are exposed to market fluctuations in energy commodity prices impacting our power and gas operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate risk related to existing debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2004 to December 31, 2005. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2005
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance in AOCI, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value	(3)	(2)	(5)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(26)	4	(22)
Ending Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ (5)	$ (2)	$ (7)

Credit Risk

We limit credit risk in our marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. Our analysis, in conjunction with the rating agencies' information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2005, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 12.05%, expressed in terms of net MTM assets and net receivables. As of December 31, 2005, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 930	$ 330	$ 600	1	$ 111
Split Rating	3	-	3	2	3
Noninvestment Grade	242	152	90	3	80
No External Ratings:					
Internal Investment Grade	173	-	173	1	116
Internal Noninvestment Grade	18	2	16	3	12
Total	$ 1,366	$ 484	$ 882	10	$ 322

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2008. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
December 31, 2005

	2006	2007	2008
Estimated Plant Output Hedged	91%	88%	90%

VaR Associated with Risk Management Contracts

Commodity Price Risk

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

VaR Model

December 31, 2005 (in millions)				December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$5	$3	$1	$3	$19	$5	$1

The 2004 High VaR occurred in January 2004 during a period when international coal and freight prices experienced record high levels and extreme volatility. Within the following month, the VaR returned to levels approaching the average VaR for the year.

Interest Rate Risk

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $615 million at December 31, 2005 and $601 million at December 31, 2004. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of operations, cash flows, and changes in common shareholders' equity and comprehensive income (loss), for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003; and FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Notes 8, 16 and 17 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus,Ohio
February 27, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that American Electric Power Company, Inc. and subsidiary companies (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and the financial statement schedule as of and for the year ended December 31, 2005 of the Company and our reports dated February 27, 2006 expressed an unqualified opinion on those financial statements (and with respect to the report on those financial statements, included an explanatory paragraph concerning the Company's adoption of new accounting pronouncements in 2003, 2004 and 2005) and the financial statement schedule.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

AEP management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2005. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, the Company's internal control over financial reporting was effective as of December 31, 2005.

AEP's independent registered public accounting firm has issued an attestation report on our assessment of the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2005, 2004 and 2003
(in millions, except per-share amounts)

	2005	2004	2003
REVENUES			
Utility Operations	$ 11,193	$ 10,664	$ 11,030
Gas Operations	463	3,068	3,100
Other	455	513	703
TOTAL	12,111	14,245	14,833
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,592	3,059	3,147
Purchased Energy for Resale	687	670	707
Purchased Gas for Resale	256	2,807	2,850
Maintenance and Other Operation	3,649	3,700	3,776
Asset Impairments and Other Related Charges	39	-	650
Gain/Loss on Disposition of Assets, Net	(120)	(4)	(48)
Depreciation and Amortization	1,318	1,300	1,307
Taxes Other Than Income Taxes	763	730	701
TOTAL	10,184	12,262	13,090
OPERATING INCOME	1,927	1,983	1,743
Investment Income	105	33	25
Carrying Costs	55	302	-
Allowance For Equity Funds Used During Construction	21	15	14
Investment Value Losses	(7)	(15)	(70)
Gain on Disposition of Equity Investments, Net	56	153	-
INTEREST AND OTHER CHARGES			
Interest Expense	697	781	814
Preferred Stock Dividend Requirements of Subsidiaries	7	6	9
Minority Interest in Finance Subsidiary	-	-	17
TOTAL	704	787	840
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	1,453	1,684	872
Income Tax Expense	430	572	358
Minority Interest Expense	4	3	2
Equity Earnings of Unconsolidated Subsidiaries	10	18	10
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	1,029	1,127	522
DISCONTINUED OPERATIONS, Net of Tax	27	83	(605)
EXTRAORDINARY LOSS, Net of Tax	(225)	(121)	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax			
Accounting for Risk Management Contracts	-	-	(49)
Asset Retirement Obligations	(17)	-	242
NET INCOME	$ 814	$ 1,089	$ 110
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	390	396	385
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.64	$ 2.85	$ 1.35
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51
TOTAL BASIC EARNINGS PER SHARE	$ 2.09	$ 2.75	$ 0.29
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	391	396	385
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.63	$ 2.85	$ 1.35
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51
TOTAL DILUTED EARNINGS PER SHARE	$ 2.08	$ 2.75	$ 0.29
CASH DIVIDENDS PAID PER SHARE	$ 1.42	$ 1.40	$ 1.65

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in millions)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 401	$ 320
Other Temporary Cash Investments	127	275
Accounts Receivable:		
Customers	826	830
Accrued Unbilled Revenues	374	665
Miscellaneous	51	84
Allowance for Uncollectible Accounts	(31)	(77)
Total Receivables	1,220	1,502
Fuel, Materials and Supplies	726	852
Risk Management Assets	926	737
Margin Deposits	221	113
Regulatory Asset for Under-Recovered Fuel Costs	197	7
Other	127	190
TOTAL	3,945	3,996
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,653	15,969
Transmission	6,433	6,293
Distribution	10,702	10,280
Other (including gas, coal mining and nuclear fuel)	3,116	3,593
Construction Work in Progress	2,217	1,159
Total	39,121	37,294
Accumulated Depreciation and Amortization	14,837	14,493
TOTAL - NET	24,284	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,262	3,594
Securitized Transition Assets and Other	593	642
Spent Nuclear Fuel and Decommissioning Trusts	1,134	1,053
Investments in Power and Distribution Projects	97	154
Goodwill	76	76
Long-term Risk Management Assets	886	470
Employee Benefits and Pension Assets	1,105	422
Other	746	800
TOTAL	7,899	7,211
Assets Held for Sale	44	628
TOTAL ASSETS	$ 36,172	$ 34,636

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,144	$ 1,055
Short-term Debt	10	23
Long-term Debt Due Within One Year	1,153	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	906	608
Accrued Taxes	651	611
Accrued Interest	183	185
Customer Deposits	571	414
Other	842	749
TOTAL	5,460	4,990
NONCURRENT LIABILITIES		
Long-term Debt	11,073	11,008
Long-term Risk Management Liabilities	723	329
Deferred Income Taxes	4,810	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,747	2,522
Asset Retirement Obligations	936	827
Employee Benefits and Pension Obligations	355	730
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	157	166
Deferred Credits and Other	762	419
TOTAL	21,563	20,820
Liabilities Held for Sale	-	250
TOTAL LIABILITIES	27,023	26,060
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2005	2004
Shares Authorized	600,000,000	600,000,000
Shares Issued	415,218,830	404,858,145

	2005	2004
(21,499,992 and 8,999,992 shares were held in treasury at December 31, 2005 and 2004, respectively)	2,699	2,632
Paid-in Capital	4,131	4,203
Retained Earnings	2,285	2,024
Accumulated Other Comprehensive Income (Loss)	(27)	(344)
TOTAL	9,088	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 36,172	$ 34,636

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in millions)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 814	$ 1,089	$ 110
(Income) Loss from Discontinued Operations	(27)	(83)	605
Income from Continuing Operations	787	1,006	715
Adjustments for Noncash Items:			
Depreciation and Amortization	1,318	1,300	1,307
Accretion of Asset Retirement Obligations	63	64	59
Deferred Income Taxes	65	291	163
Deferred Investment Tax Credits	(32)	(29)	(33)
Cumulative Effect of Accounting Changes, Net	17	-	(193)
Asset Impairments, Investment Value Losses and Other Related Charges	46	15	720
Carrying Costs	(55)	(302)	-
Extraordinary Loss	225	121	-
Amortization of Deferred Property Taxes	(17)	(3)	(2)
Amortization of Cook Plant Restart Costs	-	-	40
Mark-to-Market of Risk Management Contracts	84	14	(122)
Pension Contributions to Qualified Plan Trusts	(626)	(231)	(58)
Over/Under Fuel Recovery	(239)	96	239
Gain on Sales of Assets and Equity Investments, Net	(176)	(157)	(48)
Change in Other Noncurrent Assets	(28)	(100)	(24)
Change in Other Noncurrent Liabilities	3	196	(73)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(7)	280	473
Fuel, Materials and Supplies	(20)	33	(52)
Accounts Payable	140	(306)	(764)
Taxes Accrued	48	427	87
Customer Deposits	157	35	194
Other Current Assets	(56)	(47)	(2)
Other Current Liabilities	180	8	(126)
Net Cash Flows From Operating Activities	1,877	2,711	2,500
INVESTING ACTIVITIES			
Construction Expenditures	(2,404)	(1,637)	(1,322)
Change in Other Temporary Cash Investments, Net	76	32	(91)
Investment in Discontinued Operations, Net	-	(59)	(615)
Purchases of Investment Securities	(8,836)	(1,574)	(1,022)
Sales of Investment Securities	8,934	1,620	736
Acquisitions of Assets	(360)	-	-
Proceeds from Sales of Assets	1,606	1,357	82
Other	(21)	(68)	(66)
Net Cash Flows Used For Investing Activities	(1,005)	(329)	(2,298)
FINANCING ACTIVITIES			
Issuance of Common Stock	402	17	1,142
Repurchase of Common Stock	(427)	-	-
Issuance of Long-term Debt	2,651	682	4,761
Change in Short-term Debt, Net	(13)	(409)	(2,797)
Retirement of Long-term Debt	(2,729)	(2,511)	(2,707)
Dividends Paid on Common Stock	(553)	(555)	(618)
Other	(122)	(64)	(290)
Net Cash Flows Used For Financing Activities	(791)	(2,840)	(509)
Net Increase (Decrease) in Cash and Cash Equivalents	81	(458)	(307)
Cash and Cash Equivalents at Beginning of Period	320	778	1,085
Cash and Cash Equivalents at End of Period	$ 401	$ 320	$ 778
CASH FLOWS FROM DISCONTINUED OPERATIONS (Revised - see Note 1)			
Operating Activities	$ -	$ (3)	$ 12
Investing Activities	-	(10)	(13)
Financing Activities	-	-	(9)
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	-	(13)	(10)
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	13	23
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ -	$ 13

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004, and 2003
(in millions)

	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	348	$ 2,261	$ 3,413	$ 1,999	$ (609)	$ 7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(618)		(618)
Common Stock Expense			(35)			(35)
Other			(6)	(1)		(7)
TOTAL						7,581
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					106	106
Cash Flow Hedges, Net of Tax of $42					(78)	(78)
Securities Available for Sale, Net of Tax of $0					1	1
Minimum Pension Liability, Net of Tax of $75					154	154
NET INCOME				110		110
TOTAL COMPREHENSIVE INCOME						293
DECEMBER 31, 2003	404	2,626	4,184	1,490	(426)	7,874
Issuance of Common Stock	1	6	11			17
Common Stock Dividends				(555)		(555)
Other			8			8
TOTAL						7,344
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(104)	(104)
Cash Flow Hedges, Net of Tax of $51					94	94
Minimum Pension Liability, Net of Tax of $52					92	92
NET INCOME				1,089		1,089
TOTAL COMPREHENSIVE INCOME						1,171
DECEMBER 31, 2004	405	2,632	4,203	2,024	(344)	8,515
Issuance of Common Stock	10	67	335			402
Common Stock Dividends				(553)		(553)
Repurchase of Common Stock			(427)			(427)
Other			20			20
TOTAL						7,957
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(6)	(6)
Cash Flow Hedges, Net of Tax of $15					(27)	(27)
Securities Available for Sale, Net of Tax of $11					20	20
Minimum Pension Liability, Net of Tax of $175					330	330
NET INCOME				814		814
TOTAL COMPREHENSIVE INCOME						1,131
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES
INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of our electric utility operating companies is the generation, transmission and distribution of electric power. Two of those electric utility operating companies are completing the final stage of exiting the generation business. Two of our electric utility operating companies provide only transmission and distribution services. One of our companies is an electricity generation business. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated independent power and cogeneration facilities, coal mining and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale power markets. Wholesale power markets are generally market-based and are not cost-based regulated unless a wholesaler negotiates and files a cost-based rate contract with the FERC or a generator/seller of wholesale power is determined by the FERC to have "market power." The FERC also regulates transmission service and rates particularly in states that have restructured and unbundled rates. The state commissions regulate all or portions of our retail operations and retail rates dependent on the status of customer choice in each state jurisdiction (see Note 6).

For the periods presented, we were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (PUHCA 1935). The Energy Policy Act of 2005 repealed PUHCA 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA 2005). With the repeal of PUHCA 1935, the SEC no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over holding company-related activities has been transferred to the FERC. Regulations and required reporting under PUHCA 2005 are reduced compared to those under PUHCA 1935. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially-controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Operations. We also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see "Guarantees of Third Party Obligations" section of Note 8 and "Gavin Scrubber Financing Arrangement" section of Note 16). We also have generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and our proportionate share of the assets and liabilities are reflected in our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. We discontinued the application of SFAS 71 for the generation portion of our business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, goodwill and intangible asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

We implemented SFAS 143 effective January 1, 2003 and FIN 47 effective December 31, 2005 (see "Accounting for Asset Retirement Obligations (ARO)" section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined that an other than temporary loss in value has occurred.

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Property, Plant and Equipment is disclosed as regulated/nonregulated by functional class within the Depreciation, Depletion and Amortization section below.

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,411	$ 4,166	2.7 - 3.8	30 - 120	$ 9,242	$ 4,019	2.6 - 3.3	20 - 120
Transmission	6,433	2,280	1.7 - 3.0	25 - 75	-	-	N.M.	N.M.
Distribution	10,702	3,085	3.1 - 4.1	10 - 75	-	-	N.M.	N.M.
CWIP	1,341	(14)	N.M.	N.M.	876	(3)	N.M.	N.M.
Other	2,266	992	5.1 - 16.0	N.M.	850	312	2.0 - 4.9	2 - 37
Total	$ 28,153	$ 10,509			$ 10,968	$ 4,328		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,276	$ 4,004	2.7 - 3.8	30 - 120	$ 8,693	$ 3,879	2.6 - 3.9	20 - 120
Transmission	6,293	2,241	1.7 - 3.0	25 - 75	-	-	N.M	N.M
Distribution	10,280	3,043	3.2 - 4.1	10 - 75	-	-	N.M.	N.M.
CWIP	712	4	N.M.	N.M.	447	-	N.M.	N.M.
Other	2,258	922	5.4 - 16.4	N.M.	1,335	400	2.0 - 14.2	0 - 50
Total	$ 26,819	$ 10,214			$ 10,475	$ 4,279		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(%)	(in years)	(%)	(in years)
Production	2.5 - 3.8	30 - 120	2.3 - 3.9	35 - 120
Transmission	1.7 - 3.1	25 - 75	2.1 - 2.8	33 - 65
Distribution	3.3 - 4.2	10 - 75	N.M.	N.M.
Other	7.1 - 16.7	N.M.	2.0 - 15.6	2 - 50

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.66, $0.65 and $0.25 per ton in 2005, 2004 and 2003, respectively. In 2004, average amortization rates increased from 2003 due to a lower tonnage nomination from the power plant yielding a higher cost per ton. In addition, coal mining assets amortized at a lower rate were sold in 2004.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are debited to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see "Accounting for Asset Retirement Obligations (ARO)" section of this note).

Accounting for Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

We have legal obligations for nuclear decommissioning costs for our Cook Plant, as well as for the retirement of certain ash ponds, wind farms and certain coal mining facilities. As of December 31, 2005 and 2004, our ARO liability was $946 million and $1,076 million, respectively, and included $731 million and $711 million for nuclear decommissioning of the Cook Plant.

As of December 31, 2005 and 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $870 million and $934 million, respectively, of which $870 million and $791 million relating to the Cook Plant are recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that were legally restricted for purposes of settling the nuclear decommissioning liabilities for STP was $143 million as of December 31, 2004. These assets, which were sold in 2005, are classified as Assets Held for Sale on our 2004 Consolidated Balance Sheet. Due to the sale, we are no longer responsible for the STP decommissioning liabilities.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

In the fourth quarter of 2005, we recorded $55 million of ARO in accordance with FIN 47. The liabilities are primarily related to the removal and disposal of asbestos in general buildings and generating plants (See "FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligation" (FIN 47)" and "Cumulative Effect of Accounting Changes" sections of Note 2).

The following is a reconciliation of the 2004 and 2005 aggregate carrying amounts of ARO:

	Amount (in millions)
ARO at January 1, 2004, Including Held for Sale	$ 899
Accretion Expense	64
Foreign Currency Translation	1
Liabilities Incurred	18
Liabilities Settled (a)	(57)
Revisions in Cash Flow Estimates	151
ARO at December 31, 2004, Including Held for Sale	1,076
Less ARO Held for Sale:	
South Texas Project (b)	(249)
ARO at December 31, 2004	$ 827
ARO at January 1, 2005, Including Held for Sale	$ 1,076
Accretion Expense	63
Liabilities Incurred (c)	76
Liabilities Settled	(4)
Revisions in Cash Flow Estimates	(9)
Less ARO Liability for:	
South Texas Project (b)	(256)
ARO at December 31, 2005 (d)	$ 946

(a) Liabilities Settled in 2004 predominantly include noncash reductions of ARO associated with the sales of the U.K. generation assets in July 2004 and AEP Coal Company, Inc. in March 2004.
(b) The ARO related to nuclear decommissioning costs for TCC's share of STP was transferred to the buyer in connection with the May 2005 sale (see "Dispositions" section of Note 10).
(c) Includes $55 million of ARO relating to the adoption of FIN 47.
(d) The current portion of our ARO, totaling $10 million, is included in Other in the Current Liabilities section of our 2005 Consolidated Balance Sheet.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were $56 million, $37 million and $37 million in 2005, 2004 and 2003, respectively.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Temporary Cash Investments, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

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

Other Temporary Cash Investments

Other Temporary Cash Investments include marketable securities that we intend to hold for less than one year and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Cash Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities reflected in Other Temporary Cash Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

The following is a summary of Other Temporary Cash Investments at December 31:

	2005				2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash (a)	$ 96	$ -	$ -	$ 96	$ 106	$ -	$ -	$ 106
Government Debt Securities	-	-	-	-	144	-	-	144
Corporate Equity Securities	2	29	-	31	25	-	-	25
Total Other Temporary Cash Investments	$ 98	$ 29	$ -	$ 127	$ 275	$ -	$ -	$ 275

(a) primarily represents amounts held for the payment of debt.

Proceeds from sales of current available-for-sale securities were $8,228 million, $670 million and $115 million in 2005, 2004 and 2003, respectively. Purchases of current available-for-sale securities were $8,075 million, $573 million and $314 million in 2005, 2004 and 2003, respectively. Gross realized gains from the sale of current available-for-sale securities were $47 million in 2005 and were not material in 2004 or 2003. Gross realized losses from the sale of current available-for-sale securities were not material in 2005, 2004 or 2003.

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost. Gas inventory was carried at the lower of weighted average cost or market during 2004. Due to the sale of HPL in 2005, we no longer own any gas inventories.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheets (see "Sale of Receivables – AEP Credit" section of Note 17).

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. that are included in our consolidated financial statements and investments outside the U.S. that are accounted for under the equity method are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52, "Foreign Currency Translation." Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The foreign currency translation balance of Accumulated Other Comprehensive Income (Loss) as of December 31, 2004 and 2005 has been reduced significantly primarily due to the disposition of our U.K. assets in 2004, which is reflected in Discontinued Operations on our Consolidated Statements of Operations. In addition, in 2004 and 2005, we disposed of various non-U.S. equity method investments.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Notes 4 and 6). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana, Michigan and West Virginia), where fuel clauses have been capped, frozen or suspended for a period of years, fuel costs impact earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze ended on March 1, 2004. Through subsequent orders, the Indiana Utility Regulatory Commission (IURC) authorized the billing of capped fuel rates on an interim basis until April 1, 2005 and subsequently extended these rates until June 30, 2007. In West Virginia, deferred fuel accounting for over- or under-recovery will begin July 1, 2006. Changes in fuel costs also impact earnings for certain of our IPP generating units that do not have long-term contracts for their fuel supply or have not hedged fuel costs (see Notes 4 and 6).

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets in our Consolidated Balance Sheets. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our Consolidated Statements of Operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase-and-sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, prior to settlement, the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period are recognized as Revenues. If the contract results in the physical delivery of power, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded gross as Purchased Energy for Resale. If the contract does not physically deliver, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded as Revenues in our Consolidated Statements of Operations on a net basis (see "Derivatives and Hedging" section of Note 14).

Domestic Gas Pipeline and Storage Activities

As a result of the sale of HPL in 2005, our domestic gas pipeline and storage activities have ceased. Prior to the sale of HPL, revenues were recognized from domestic gas pipeline and storage services when gas was delivered to contractual meter points or when services were provided, with the exception of certain physical forward gas purchase-and-sale contracts that were derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues in our Consolidated Statements of Operations. The unrealized and realized gains and losses on physically-settled resale gas contracts for the purchase of natural gas are presented as Purchased Gas for Resale in our Consolidated Statements of Operations (see "Fair Value Hedging Strategies" section of Note 14).

Energy Marketing and Risk Management Activities

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

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

After January 1, 2003, revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow or fair value hedge relationship or as a normal purchase and sale. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in our Consolidated Statements of Operations on a net basis. In jurisdictions subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

We participate in wholesale marketing and risk management activities in electricity and gas. For all contracts the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in revenues on a net basis. Unrealized mark-to-market losses and gains are included in the balance sheets as Risk Management Asset or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge) or as hedges of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in our Consolidated Statements of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and depending upon the specific nature of the risk being hedged, subsequently reclassified into Revenues or fuel expenses in our Consolidated Statements of Operations when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in our Consolidated Statements of Operations immediately (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" sections of Note 14).

Construction Projects for Outside Parties

We engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred and billed to the outside party.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

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

We classify instruments that have an unconditional obligation requiring us to redeem the instruments by transferring an asset at a specified date as liabilities on our Consolidated Balance Sheets. Those instruments consist of Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as of December 31, 2004. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Expense. In accordance with SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," dividends from prior periods remain classified as preferred stock dividends, a component of Preferred Stock Dividend Requirements of Subsidiaries, on our Consolidated Statements of Operations.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. Purchased goodwill and intangible assets with indefinite lives are not amortized. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. Goodwill is tested at the reporting unit level and other intangibles are tested at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods. Intangible assets with finite lives are amortized over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlement received at no cost from the Federal EPA. We follow the inventory model for all allowances. Allowances expected to be consumed within one year are reported in Fuel, Materials and Supplies. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets-Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Utility Operations Revenue because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- acceptable investments (rated investment grade or above);
- maximum percentage invested in a specific type of investment;
- prohibition of investment in obligations of the applicable company or its affiliates; and
- withdrawals permitted only for payment of decommissioning costs and trust expenses.

Trust funds are maintained for each regulatory jurisdiction and managed by external investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Spent Nuclear Fuel and Decommissioning Trusts for amounts relating to the Cook Plant and were included in Assets Held for Sale for amounts relating to STP in 2004. STP was sold in 2005. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

The following is a summary of nuclear trust fund investments at December 31:

	2005				2004			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)							
Cash	$ 21	$ -	$ -	$ 21	$ 22	$ -	$ -	$ 22
Debt Securities	691	7	(7)	691	691	10	(4)	697
Equity Securities	277	148	(3)	422	330	149	(2)	477
Total Nuclear Trust Fund Investments	989	155	(10)	1,134	1,043	159	(6)	1,196
Less: Investments Included in Assets Held for Sale	-	-	-	-	(107)	(37)	1	(143)
Spent Nuclear Fuel and Decommissioning Trusts	$ 989	$ 155	$ (10)	$ 1,134	$ 936	$ 122	$ (5)	$ 1,053

Proceeds from sales of nuclear trust fund investments were $706 million, $950 million and $621 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $761 million, $1,001 million and $708 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $13 million, $13 million and $26 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $17 million, $18 million and $6 million in 2005, 2004 and 2003, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2005 is as follows:

	Fair Value (in millions)
Within 1 year	$ 17
1 year – 5 years	298
5 years – 10 years	173
After 10 years	203
	$ 691

Comprehensive Income (Loss)

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

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

	December 31,	
Components	2005	2004
	(in millions)	
Foreign Currency Translation Adjustments, Net of Tax	$ -	$ 6
Securities Available for Sale, Net of Tax	19	(1)
Cash Flow Hedges, Net of Tax	(27)	-
Minimum Pension Liability, Net of Tax	(19)	(349)
Total	$ (27)	$ (344)

Stock-Based Compensation Plans

At December 31, 2005, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan (see Note 12). No stock option expense is reflected in our earnings, as AEP currently accounts for stock options under APB 25 and all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant.

We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, as well as stock units to nonemployee members of our Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors is a nonqualified deferred compensation plan that permits directors to choose to defer up to 100 percent of their annual Board retainer into any of a variety of investment fund options, all with market based returns, including the AEP stock fund. The Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units.

The following table shows the effect on our Net Income and Earnings per Share as if we had applied fair value measurement and recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation awards:

	Year Ended December 31,		
	2005	2004	2003
	(in millions, except per share data)		
Net Income, as reported	$ 814	$ 1,089	$ 110
Add: Stock-based Compensation Expense Included in Reported Net Income, Net of Tax	22	15	2
Deduct: Stock-based Compensation Expense determined Under Fair Value Based Method for All Awards, Net of Tax	(22)	(18)	(7)
Pro Forma Net Income	$ 814	$ 1,086	$ 105
Earnings per Share:			
Basic – As Reported	$ 2.09	$ 2.75	$ 0.29
Basic – Pro Forma (a)	$ 2.09	$ 2.74	$ 0.27
Diluted – As Reported	$ 2.08	$ 2.75	$ 0.29
Diluted – Pro Forma (a)	$ 2.08	$ 2.74	$ 0.27

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2005	2004	2003
	(in millions)		
Weighted Average Shares			
Basic Average Common Shares Outstanding	390	396	385
Assumed Conversion of Dilutive Stock Options and Awards (see Note 12)	1	-	-
Diluted Average Common Shares Outstanding	391	396	385

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share.

Options to purchase 0.5 million, 5.2 million and 5.6 million shares of common stock were outstanding at December 31, 2005, 2004 and 2003, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there was no effect on diluted earnings per share in 2004 and 2003 related to our equity units (issued in 2002) because the market value of our common stock did not exceed $49.08 per share. The equity units were settled in 2005 (see "Equity Units and Remarketing of Senior Notes" section of Note 17).

Supplementary Information

	Year Ended December 31,		
	2005	**2004**	**2003**
Related Party Transactions		**(in millions)**	
AEP Consolidated Purchased Energy:			
Ohio Valley Electric Corporation (43.47% Owned)	$ 196	$ 161	$ 147
Sweeny Cogeneration Limited Partnership (50% Owned)	141	-	-
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	20	14	9
Cash Flow Information			
Cash was paid (received) for:			
Interest (Net of Capitalized Amounts)	637	755	741
Income Taxes	439	(107)	163
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	63	123	45
Assumption (Disposition) of Liabilities Related to Acquisitions/Divestitures, Net	(18)	(67)	-
Noncash Construction Expenditures Included in Accounts Payable at December 31	253	116	92
Increase in Assets and Liabilities Resulting from:			
Consolidation of VIEs Due to the adoption of FIN 46	-	-	547
Consolidation of Merchant Power Generation Facility	-	-	496

Power Projects

We own a 50% interest in a domestic unregulated power plant with a capacity of 480 MW located in Texas and an international power plant totaling 600 MW located in Mexico (see "Other Losses" section of Note 10). We sold our interest in the international power plant in February 2006.

We account for investments in power projects that are 50% or less owned using the equity method and report them as Investments in Power and Distribution Projects on our Consolidated Balance Sheets. At December 31, 2005 and 2004, the 50% owned domestic power project and international power investment are accounted for under the equity method and have unrelated third-party partners. The domestic project is a combined cycle gas turbine that provides steam to a host commercial customer and is considered a Qualifying Facility (QF) under PURPA. The international power investment is classified as a Foreign Utility Company (FUCO) under the Energy Policies Act of 1992.

Both the international and domestic power projects have project-level financing, which is nonrecourse to AEP. In addition, for the international project, AEP guaranteed $48 million of letters of credit associated with the financing and a $10 million letter of credit for the benefit of the power purchaser under the power supply contract.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

On our Consolidated Balance Sheets, we reclassified $103 million of auction rate securities as of December 31, 2004 to Other Temporary Cash Investments from Cash and Cash Equivalents. At December 31, 2003, auction rate securities approximated $200 million.

On our Consolidated Statements of Operations, we reclassified the consumption of emission allowances and consumption of chemicals used in the generation of power from Maintenance and Other Operation to Fuel and Other Consumables Used for Electric Generation. These reclassifications totaled $110 million and $89 million for 2004 and 2003, respectively. We also reclassified the net gain or loss on the sales of emission allowances from Maintenance and Other Operation to Utility Operations Revenues. These reclassifications were not material for 2004 or 2003.

On our Consolidated Statements of Cash Flows, we have separately disclosed the operating, investing and financing portions of the cash flows attributable to our discontinued operations, which in prior periods were reported on a combined basis as a single amount. Additionally, we have included purchases and sales of auction rate securities and investments within our nuclear decommissioning and spent nuclear fuel trusts as a component of Investing Activities.

These revisions had no impact on our previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

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

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

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." A cumulative effect of a change in accounting principle will be recorded for the effect of initially applying the statement.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. SFAS 154 was effective for us beginning January 1, 2006 and will be applied as necessary.

FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

We adopted FIN 47 during the fourth quarter of 2005. In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143, "Accounting for Asset Retirement Obligations." FIN 47 clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

We completed a review of our FIN 47 conditional ARO and concluded that we have legal liabilities for asbestos removal and disposal in general buildings and generating plants. In the fourth quarter of 2005, we recorded $55 million of conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to regulatory liability. Of the $55 million, we recorded an unfavorable cumulative effect of $26 million ($17 million, net of tax) for our nonregulated operations related to asbestos removal in the Utility Operations segment.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligations would only be recognized if and when we abandon or cease the use of specific easements.

Pro forma net income and earnings per share are not presented for the years ended December 31, 2004 and 2003 because the pro forma application of FIN 47 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods.

As of December 31, 2004 and 2003, the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted at the beginning of each period was $52 million and $49 million, respectively.

See "Accounting for Asset Retirement Obligations (ARO)" section of Note 1 for further discussion.

EITF Issue 03-13 "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations"

This issue developed a model for evaluating cash flows in determining whether cash flows have been or will be eliminated and also what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We applied this issue to components we disposed or classified as held for sale, including the HPL disposition (see "Houston Pipe Line Company" section of Note 10).

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions," if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

Future Accounting Changes

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

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in our Consolidated Statements of Operations as Extraordinary Loss, Net of Tax (see "Texas True-Up Proceedings" section of Note 6).

In the fourth quarter of 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis, including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in a nonaffiliated utility's true-up order (see "Wholesale Capacity Auction True-up and Stranded Plant Cost" section of Note 6). These net adjustments were recorded as an extraordinary item of $121 million net of tax in accordance with SFAS 101 and are reflected in our Consolidated Statements of Operations as Extraordinary Loss, Net of Tax.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10, "Accounting for Contracts Included in Energy Trading and Risk Management Activities," and related interpretive guidance. We recorded a $49 million net of tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in 2003 ($13 million in Utility Operations, $22 million in Investments – Gas Operations and $14 million in Investments – UK Operations segments). These amounts are recognized as the positions settle.

Asset Retirement Obligations

In 2003, we recorded $242 million of net of tax income as a cumulative effect of accounting change for ARO in accordance with SFAS 143 ($249 million net of tax income in Utility Operations and $7 million net of tax loss in Investments - UK Operations segment).

In the fourth quarter of 2005, we recorded $17 million of net of tax loss as a cumulative effect of accounting change for ARO in accordance with FIN 47 in the Utility Operations segment.

See table below for details of the Cumulative Effect of Accounting Changes:

	Year Ended December 31, 2005	2004	2003
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$ -	$ -	$ (49)(b)
Asset Retirement Obligations (SFAS 143)	-	-	242 (c)
Asset Retirement Obligations (FIN 47)	(17)(a)	-	-
Total	$ (17)	$ -	$ 193

(a) net of tax of $9 million
(b) net of tax of $19 million
(c) net of tax of $157 million

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2005 and 2004 by operating segment are:

	Utility Operations	Investments - Other	AEP Consolidated
Balance at January 1, 2004	$ 37.1	$ 41.4	$ 78.5
Goodwill Written Off Related to Sale of Numanco	-	(2.6)	(2.6)
Balance at December 31, 2004	$ 37.1	$ 38.8	$ 75.9
Balance at January 1, 2005	$ 37.1	$ 38.8	$ 75.9
Impairment Losses	-	-	-
Balance at December 31, 2005	$ 37.1	$ 38.8	$ 75.9

In the fourth quarters of 2004 and 2005, we prepared our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses required.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $23.9 million at December 31, 2005 and $29.7 million at December 31, 2004, net of accumulated amortization and are included in Other Noncurrent Assets on our Consolidated Balance Sheets. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2005		December 31, 2004	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Patent	5	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Easements	10	2.2	0.7	2.2	0.5
Trade Name and Administration of Contracts	7	-	-	2.4	0.9
Purchased Technology	10	10.9	4.3	10.9	3.2
Advanced Royalties	10	29.4	13.6	29.4	10.6
Total		$ 42.6	$ 18.7	$ 45.0	$ 15.3

Amortization of intangible assets was $4 million, $4 million and $5 million for 2005, 2004 and 2003, respectively. Our estimated total amortization is $5 million per year for 2006 and 2007, $4 million per year for 2008 through 2010 and $2 million in 2011.

"Trade Name and Administration of Contracts" represents intangible assets related to HPL, which was sold in 2005 (see "Houston Pipeline Company" section of Note 10).

4. RATE MATTERS

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request included incurred and projected costs from July 1, 2004 through June 30, 2006 which relate to (i) environmental controls on coal-fired generators to meet the first phase of the final Clean Air Interstate Rule and Clean Air Mercury Rule issued in 2005, (ii) the Wyoming-Jacksons Ferry 765 kilovolt transmission line construction and (iii) other incremental T&D system reliability work.

In the filing, APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. In October 2005, the Virginia SCC denied APCo's request to place the proposed cost recovery surcharge in effect, on an interim basis subject to refund. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the public hearing in this case which began on February 27, 2006.

The Virginia SCC also ruled that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, the order permitted APCo to update its request to reflect additional actual costs and/or present additional evidence. Accordingly, in November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery of E&R costs to $21 million of actual incremental E&R costs incurred during the period July 1, 2004 through September 30, 2005.

Through December 31, 2005, APCo deferred $24 million of recorded E&R costs. It has not yet recorded $4 million of such costs which represent equity carrying costs that are not recognized until collected through regulated rates. In addition, APCo reversed $5 million of AFUDC/interest capitalized through December 31, 2005 related to incremental E&R capital investments that would have been duplicative of a portion of the deferred E&R carrying costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to include $20 million of incremental E&R costs in its electric rates. The staff also recommended the disallowance of the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that have been established as a regulatory asset as of December 31, 2005. We believe the staff's position is contrary to the Virginia SCC's October 2005 order, which denied APCo's request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs after the commission examines and approves such costs. If the Virginia SCC denies recovery of any of APCo's deferred E&R costs, the denial could adversely impact future results of operations and cash flows. Hearings began on February 27, 2006.

APCo and WPCo West Virginia Rate Case

In August 2005, APCo and WPCo collectively filed an application with the WVPSC seeking an initial increase in their retail rates of approximately $82 million. The initial increase requests approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism, which accounts for $72 million of the initial increase. The request also seeks approval to implement a system reliability tracker, which accounts for $10 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins transmission items.

In addition, APCo and WPCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively.

APCo has a regulatory liability of $52 million for pre-suspension over-recovered ENEC costs. APCo proposed to apply this $52 million, along with a carrying cost, to any future under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism.

In January 2006, APCo and WPCo submitted supplemental testimony addressing the Ceredo Generating Station acquisition (see "Acquisitions" section of Note 10) and certain revisions to their filing. The supplemental filing revised the initial requested increase of $82 million downward to $74 million. APCo revised the supplemental increases downward to $43 million, $8 million and $36 million, effective on January 1, 2007, 2008 and 2009, respectively.

In January 2006, APCo, WPCo and the WVPSC staff filed a joint motion requesting a change in the procedural schedule. The motion, as modified, requests that hearings begin in April 2006, new rates go into effect on July 28, 2006 and deferral accounting for over – or under – recovery of the ENEC costs begins July 1, 2006. In response to that motion, the WVPSC approved the proposed schedule including the commencement date for ENEC deferral accounting. At this time, we cannot predict the ultimate effect on future revenues, results of operations and cash flows of APCo's and WPCo's base rate increase proceeding in West Virginia.

I&M Indiana Settlement Agreement

In 2003, I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain parties to the negotiations reached a settlement. The IURC approved the settlement agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate. Total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor was adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at the Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate). If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If the Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

I&M experienced a cumulative under-recovery of fuel costs for the period March 2004 through December 2005 of $12 million. Since I&M expects that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, I&M recorded $9 million and $3 million of under-recoveries as fuel expense in 2005 and 2004, respectively. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, future results of operations and cash flows would be adversely affected.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC which seeks authorization effective January 1, 2006 to revise the book depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in customers' electric service rates. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. If approved, the book depreciation expense reduction would increase earnings, but would not impact cash flows. Hearings are scheduled to begin in May 2006. When approved by the IURC, I&M will prospectively revise its book depreciation rates and, if appropriate, currently adjust its book depreciation expense to the approved effective date.

KPCo Rate Filing

In September 2005, KPCo filed a request with the Kentucky Public Service Commission (KPSC) to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase included a return on common equity of 11.5% or $26 million, the impact of reduced through-and-out transmission revenues of $10 million, recovery of additional AEP Power Pool capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. In February 2006, KPCo executed and submitted a settlement agreement to the KPSC for its approval. The major terms of the agreement are as follows: KPCo will receive a $41 million increase in revenues effective March 30, 2006, KPCo will retain its existing environmental surcharge tariff and KPCo will continue to include in the calculation of its annual depreciation expense the depreciation rates currently approved and utilized as a result of KPCo's 1991 rate case. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes. The KPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power and its Possible Impact on AEP East Companies

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO offered to collect those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs, future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between and among AEP East companies and AEP West companies and specifically PSO was inconsistent with the FERC-approved Operating Agreement and SIA and that the AEP West companies should have been allocated greater margins. The parties objected to the inclusion of mark-to-market amounts in developing the allocation base. In addition, an intervenor recommended that $9 million of the $42 million related to the 2002 reallocation not be recovered from Oklahoma retail customers because that amount was not refunded by PSO's affiliated AEP West companies to their wholesale customers outside of Oklahoma.

The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002. In July 2005, the OCC staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East companies and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins allocated to PSO and thus, a reduction in its recoverable fuel costs through December 2004 in a range of $38 million to $47 million.

In January 2006, the OCC staff and intervenors issued supplemental testimony proposing that the OCC offset the under-recovered fuel clause deferral inclusive of the $42 million with off-system sales margins of $27 million to $37 million through December 2004. The OCC staff also recommended a disallowance of $6 million. Hearings were held in early February 2006 to address the issues. PSO does not agree with the intervenors' and the OCC staff's recommendations and will defend vigorously its position.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. Intervenors appealed the ALJ ruling to the OCC. The OCC has not ruled on the intervenors' appeal or the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. The Court agreed that the FERC had jurisdiction over the SIA and that the sole remedy is at the FERC.

If the OCC decides to provide for additional off-system sales margins, it could adversely affect future results of operations and cash flows. However, if the position taken by the federal court in Texas is applied to PSO's case, the OCC would be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins due to a lack of jurisdiction. The OCC or another party could file a complaint at the FERC which could ultimately be successful, and which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To-date there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on future results of operations, cash flows and financial condition.

In April 2005, the OCC heard arguments from intervenors that requested the OCC conduct a prudence review of PSO's fuel and purchased power practices for 2003. In June 2005, the OCC asked its staff to conduct that review. The OCC staff is scheduled to file its testimony in March 2006 and the hearings are scheduled for May 2006.

PSO 2005 Fuel Factor Filing

In November 2005, PSO submitted to the OCC staff an interim adjustment to PSO's annual fuel factors. PSO's new factors were based on increased natural gas and purchased power market prices, as well as past under-recovered fuel costs. PSO implemented the new fuel factors in its December 2005 billing. The new fuel factors are estimated to increase 2006 revenues by approximately $349 million. At December 31, 2005, PSO had a deferred under-recovered fuel balance of $109 million, which includes interest and the $42 million discussed above in "PSO Fuel and Purchased Power and its Possible Impact on AEP East companies." This fuel factor adjustment will increase cash flows without impacting results of operations as any over or under-recovery of fuel cost will be deferred as a regulatory liability or regulatory asset.

PSO Rate Review

PSO was involved in an OCC staff-initiated base rate review, which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates by $41 million, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provided for a $7 million annual base revenue reduction offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminated a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provided for recovery, over 24 months, of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulated that PSO may not file for a base rate increase before April 1, 2006. The OCC approved the stipulation in May 2005 and new base rates were implemented in June 2005.

PSO 2005 Vegetation Management Filing

In June 2005, PSO filed testimony to adjust its vegetation management rate rider from the OCC-approved $12 million to $27 million. In November 2005, the OCC issued a final order approving an increase to the cap on the PSO vegetation management rider to $24 million, which is in addition to the $6 million vegetation management expenses currently included in base rates. The final order also provided for the recovery of carrying and other costs associated with converting overhead distribution lines to underground lines. We do not anticipate any material effect on income for the incremental costs associated with the increased cap as the incremental costs will be deferred and expensed in the future when the rate rider revenues are recognized.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Management is unable to predict the outcome of this initial report on future revenues, results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Issues

In November 2005, the Louisiana Public Service Commission (LPSC) amended an inquiry into the operation of the fuel adjustment clause recovery mechanisms of other Louisiana electric utilities to include SWEPCo. The inquiry was initiated to determine whether utilities had purchased fuel and power at the lowest possible price and whether suppliers offered competitive prices for fuel and purchased power during the period of January 1, 2005 through October 31, 2005.

In December 2005, the LPSC initiated a new audit of SWEPCo's historical fuel costs which will cover the years 2003 and 2004, pursuant to the LPSC's general order requiring biennial fuel reviews. Management cannot predict the outcome of these audits/reviews, but believes that SWEPCo's fuel and purchased power procurement practices were prudent and costs were properly incurred. If the LPSC disagrees and disallows fuel or purchased power costs incurred by SWEPCo, it would have an adverse effect on future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSC's merger order also provided that SWEPCo's base rates were capped through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in

SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony was filed in January 2005 and subsequent deposition proceedings are in process. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact future results of operations and cash flows.

TCC Rate Case

In August 2005, the PUCT issued an order in a base rate proceeding initiated in 2003 by a Texas municipality. The order reduced TCC's annual base rates by $9 million. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. Tariffs were approved and the rate change was implemented effective September 6, 2005. TCC and other parties have appealed this proceeding to the Texas District Court. No schedule has been set for hearing the appeals. Management cannot predict the ultimate outcome of these appeals. Also, in the third quarter of 2005, TCC reclassified $126 million of asset removal costs from Accumulated Depreciation and Amortization to Regulatory Liabilities and Deferred Investment Tax Credits on our Consolidated Balance Sheets based on a depreciation study prepared by TCC and approved by the PUCT.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court on the loss of load issue, but otherwise affirmed its decision. The amount of unaccounted-for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. Our 2005 pretax earnings were adversely affected by $3 million because of this decision. In a decision on rehearing in February 2006, the Texas Court of Appeals no longer is directing on remand that the unaccounted for energy issue be reconsidered solely based on the existing record. The prior ruling would have prevented the PUCT from considering additional evidence on the $3 million adjustment. Management cannot predict the outcome of further appeals but a reversal of the favorable court of appeals decision regarding the loss of load issue would adversely impact results of operations and cash flows.

RTO Formation/Integration Costs

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs and carrying costs incurred to originally form a new RTO (the Alliance) and subsequently to integrate into an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The FERC approved our application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years consistent with a March 2005 requested rate recovery period discussed below. The total amortization related to such costs was $5 million in 2005. As of December 31, 2005 and 2004, the AEP East companies had $31 million and $33 million, respectively, of deferred unamortized RTO formation/integration costs. We did not record $5 million and $4 million of equity carrying costs in 2005 and 2004, respectively, which are not recognized until collected.

In March 2005, AEP and two other utilities jointly filed a request with the FERC to recover their deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. In May 2005, the FERC issued an order denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the compliance filing in May 2005. In June 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In October 2005, the FERC granted our June 2005 rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. Also, the FERC, in its order, dismissed the May 2005 compliance filing as moot. Settlement discussions are still underway, and a result that would collect a portion of the costs in other PJM zones is likely, though not yet assured.

In March 2005, we also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed below in the "AEP East Transmission Requirement and Rates" section). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs).

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM OATT to recover the amount of deferred RTO formation costs to be amortized, determined to be $2 million per year. The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In a December 2005 order, the Public Utilities Commission of Ohio (PUCO) approved recovery of the amortization of RTO Formation/Integration Costs through a Transmission Cost Recovery Rider (TCRR). In Kentucky and West Virginia, we have made filings to recover the amortization of these costs (see "KPCo Rate Filing" section of this Note). The Indiana service territory of I&M is subject to a rate freeze until June 2007, so recovery will be delayed until the freeze ends.

Until all the AEP East companies can adjust their retail rates to recover the amortization of both RTO related deferred costs, results of operations and cash flows will be adversely affected by the amortizations. The proposed FERC settlement would allow and establish a reasonable carrying charge for the deferred costs. If the FERC or any state regulatory authority was to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs, it would have an adverse impact on future results of operations and cash flows. If the FERC approves a carrying charge rate that is lower than the carrying charge recognized to date, it could have an adverse effect on future results of operations and cash flows.

Transmission Rate Proceedings at the FERC

<u>FERC Order on Regional Through-and-out Rates and Mitigating SECA Revenue</u>

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through-and-out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint).

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004.

The elimination of the T&O charges for transactions between the two RTOs reduces the transmission service revenues collected by the RTOs and thereby, reduces the revenues received by transmission owners, including the AEP East companies, under the RTOs' revenue distribution protocols.

As a result of settlement negotiations in early 2004, the effective date of the SECA transition was delayed by the FERC. The delay was to give parties an opportunity to create a new regional rate regime. When the parties were unable to agree on a single regional rate proposal, the FERC ordered the two-year SECA transition period shortened to sixteen months, effective on December 1, 2004, continuing through March 31, 2006. The FERC has set SECA rate issues for hearing and indicated that the SECA rates are being recovered subject to refund or surcharge. The AEP East companies recognized net SECA revenues of $128 million in 2005. In addition, the AEP East companies recognized $11 million of net SECA revenues in December 2004. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. At this time, management is unable to determine the probable outcome of the FERC's SECA rate proceeding and its impact on future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In the March 2005 FERC filing discussed in the "RTO Formation/Integration Costs" section above, we proposed a two-step increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities, and retail choice customers with load delivery points in the AEP zone of PJM. In December 2005, the FERC approved an uncontested settlement allowing our wholesale transmission rates to increase in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues are expected to be eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when our Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under the Highway/Byway rate design proposed by AEP and AP, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kilovolt (kV) or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design which reflects the cost of the facilities in the corporate zone in which the transmission facilities are owned (License Plate Rate). The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the AEP East transmission-owning companies.

A competing Highway/Byway proposal filed by others would also produce net revenues to the AEP East transmission-owning companies, but at a much lower level. Both proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM License Plate Rate design. A group of LSEs has also made a proposal that would include 500 kV and higher existing facilities, and some facilities at lower voltages in the highway rate.

In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal. The case is scheduled for hearing in April 2006. AEP management cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on AEP revenues, compared to the License Plate Rates that will otherwise prevail beginning April 1, 2006 when the transitional SECA rates expire.

As of December 31, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will not be sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues will require cost recovery through retail rate proceedings. Rate requests are pending in Kentucky and West Virginia that address the reduction in FERC transmission revenues, (see "KPCo Rate Filing" section of this Note). In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. Management is unable to predict when and if the effect of the loss of transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

Future results of operations, cash flows and financial condition would be adversely affected if:

- the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or
- the newly approved AEP zonal transmission rates are not sufficient to replace the lost T&O/SECA revenues, or
- the FERC's review of our current SECA rates results in a rate reduction which is subject to refund, or
- any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail rates on a timely basis, or
- the FERC does not approve a new regional rate within PJM.

FERC Market Power Mitigation

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

In a December 2004 order, the FERC affirmed our conclusions that we passed both market power screen tests in all areas except SPP. Because we did not pass the market share screen in SPP, the FERC initiated proceedings under Section 206 of the Federal Power Act in which we are rebuttably presumed to possess market power in SPP. In February 2005, although we continued to believe we did not possess market power in SPP, we filed a response and proposed tariff changes to address the FERC's market-power concerns. The proposed tariff change would apply to sales that sink within the service territories of PSO, SWEPCo and TNC within SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps.

In July 2005, the FERC accepted for filing the amended tariffs effective March 6, 2005 and set for hearing three aspects of the proposed tariffs. Two parties intervened in the proceeding protesting the proposed cost-based tariffs. In October 2005, all parties and the FERC staff entered into a settlement agreement adopting AEP's proposed tariffs with minor modifications to the rates in consideration of certain long-term power supply arrangements entered into between AEP and the intervenors. In November 2005, the FERC settlement judge issued a certification of uncontested settlement recommending that the settlement agreement be adopted with minor additional provisions to AEP's tariff to bring such tariff into compliance with existing FERC policy. The settlement certification was accepted by the FERC in January 2006.

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

Management believes that we are unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows from the FERC's and PJM's market power analysis cannot be determined. Since the cost caps apply only to wholesale loads within our control area inside SPP and these entities are not often in the market for additional power, we do not expect a significant adverse impact from the FERC's actions to-date.

Allocation Agreement between AEP East Companies and AEP West Companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. The current allocation methodology was established at the time of the AEP-CSW merger and, consistent with the terms of the SIA, in November 2005, we filed a proposed allocation methodology to be used in 2006 and beyond. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of the AEP West companies. Previously, the SIA allocation provided for a different method of sharing of all such margins between both AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from the one we proposed. We requested that the new methodology be effective on a prospective basis after the FERC's order. The impact on future results of operations and cash flows will depend upon the methodology approved by the FERC, the level of future margins by region and the status of cost recovery mechanisms by state. Our total trading and marketing margins are unaffected by the allocation methodology. However, because trading and marketing activities are not treated the same for ratemaking purposes in each state retail jurisdiction and the timing of inclusion of the margins in rates may differ, our results of operations and cash flows could be affected. Management is unable to predict the ultimate effect of this filing on our future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2005	December 31, 2004	Future Recovery/Refund Period
	(in millions)		
Regulatory Assets:			
Income Tax Related Regulatory Assets, Net	$ 785	$ 796	Various Periods (a)
Transition Regulatory Assets – Ohio and Virginia	306	407	Up to 5 Years (a)
Designated for Securitization - Texas	1,436	1,361	(b) (c)
Texas Wholesale Capacity Auction True-up	77	560	(c)
Unamortized Loss on Reacquired Debt	110	116	Up to 38 Years (d)
Cook Nuclear Plant Refueling Outage Levelization	23	44	(e)
Other	525	310	Various Periods (f)
Total Noncurrent Regulatory Assets	$ 3,262	$ 3,594	
Current Regulatory Asset – Under-Recovered Fuel Costs	$ 197	$ 7	
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,437	$ 1,290	(g)
Deferred Investment Tax Credits	361	393	Up to 24 Years (a)
Excess ARO for Nuclear Decommissioning Liability	271	245	(h)
Over-recovery of Texas Fuel Costs	182	216	(c)
Deferred Over-recovered Fuel Costs	53	53	(a)
Texas Retail Clawback	75	75	(c)
Other	368	250	Various Periods (f)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,747	$ 2,522	

(a) Does not earn a return.
(b) Includes a carrying cost. The cost of the securitization bonds, when issued, would be recovered over a period of time to be determined in a future PUCT proceeding.
(c) See "Texas Restructuring" and "Carrying Costs on Net-True-up Regulatory Assets" sections of Note 6 for discussion of carrying costs. Amounts are included in TCC's and TNC's true-up proceedings for future recovery/refund over a time period to be determined in a future PUCT proceeding.
(d) Amount effectively earns a return.
(e) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(f) Includes items both earning and not earning a return.
(g) The liability for removal costs, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.
(h) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, accrues monthly, and will be paid when the nuclear plant is decommissioned.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Over-recovery of Texas Fuel Costs and Texas Retail Clawback regulatory liabilities are not currently being recovered from or returned to ratepayers. Management believes that the laws and regulations established in Texas for industry restructuring provide for the recovery from ratepayers of these net amounts. See Note 6 for a discussion of our efforts to recover these regulatory assets, net of regulatory liabilities.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reduction of $221 million over 6 years.
Indiana – I&M	Rate reduction of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreement in the remaining periods of the merger agreements, future results of operations and cash flows could be adversely affected.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of our twelve electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Michigan, Virginia and Texas) in which the AEP electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

TEXAS RESTRUCTURING

The Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. The PUCT has begun studies to consider further delay of customer choice in the SPP area of Texas. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business operates in SPP.

The Texas Restructuring Legislation provides for True-up Proceedings to determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any excess earnings (net stranded generation costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
- final approved deferred fuel balance, and
- net carrying costs on certain of the above true-up amounts.

In May 2005, TCC filed its True-Up Proceeding seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined that TCC's net true-up regulatory asset was $1.5 billion, which included carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules.

TCC adjusted its December 2005 books to reflect the PUCT's final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded in December 2005 as a pretax extraordinary loss. The difference between the requested amount of $2.4 billion, the approved amount of $1.5 billion and the recorded amount of $1.3 billion at December 31, 2005 is detailed in the table below:

	in millions
True-Up Proceeding Requested Amount	$ 2,406
Wholesale Capacity Auction True-up, including carrying costs	(572)
Commercial Unreasonableness Disallowance	(122)
Return on and of Stranded Costs Disallowance	(159)
Other	(78)
Amount Approved by the PUCT	1,475
Unrecognized but Recoverable Equity Carrying Costs and Other	(200)
Total Recorded Net True-up Regulatory Asset	$ 1,275

The requested $2.4 billion represents what TCC believes it should recover under its interpretation of the provisions of the Texas Restructuring Legislation. However, the $1.3 billion book amount reflects what management believes to be the probable recoverable net regulatory true-up asset at December 31, 2005, taking into account the PUCT's final order in TCC's True-up Proceeding exclusive of various items, principally recoverable but unrecognized equity carrying costs and other items.

Based on the PUCT-approved amount, and carrying costs through the proposed date of securitization, we anticipate requesting to securitize $1.8 billion, as discussed below in the "TCC Securitization Proceeding" section.

The Components of TCC's Net True-up Regulatory Asset as of December 31, 2005 and December 31, 2004 are:

	TCC	
	December 31, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 969	$ 897
Net Generation-related Regulatory Asset	249	249
Excess Earnings	(49)	(10)
Net Stranded Generation Costs Before Carrying Costs	1,169	1,136
Carrying Costs on Stranded Generation Plant Costs	267	225
Net Stranded Generation Costs After Carrying Costs	1,436	1,361
Wholesale Capacity Auction True-up	61	483
Carrying Costs on Wholesale Capacity Auction True-up	16	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(177)	(212)
Net Other Recoverable True-up Amounts	(161)	287
Total Recorded Net True-up Regulatory Asset	$ 1,275	$ 1,648

The majority of the reduction to TCC's net true-up regulatory asset was comprised of two extraordinary adjustments, and the associated nonextraordinary debt carrying costs. The major adjustments were related to TCC's wholesale capacity auction true-up and its stranded plant cost from the sale of its generating plants. The PUCT found that TCC did not comply with the wholesale capacity auction requirements, which resulted in a book reduction of $422 million. Related to the sale of TCC's generation assets, the PUCT determined that TCC acted in a manner that was commercially unreasonable in large part because it failed to determine a minimum price at which it would reject bids for the sale of its generating plants. Based on that determination, TCC reduced its net true-up regulatory asset by $122 million. Other smaller adjustments totaling $7 million were reversed as an extraordinary item.

In addition, the PUCT determined that the purpose of the capacity auction true-up was to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded generation plant cost balance that it determined was included in the capacity auction true-up. Since TCC had previously reduced its book stranded cost regulatory asset by $238 million in 2004 related to the duplicate depreciation, TCC increased its book stranded generation plant cost by $206 million in December 2005. The reduction to debt carrying costs related to all of these adjustments totaled $71 million.

In 2003 and 2004, based upon orders received from the PUCT, TCC recorded provisions to its over-recovered fuel balance resulting in a $209 million over-recovery regulatory liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed as nonextraordinary in the fourth quarter of 2005.

In a future proceeding, certain adjustments for the future cost-of-money benefit of accumulated deferred federal income taxes may be deducted from the recoverable true-up asset, and transferred to a separate regulatory asset to be recovered in normal delivery rates outside of the securitization process which would affect the timing of cash recovery.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. If the PUCT does not make significant changes in response to our request for reconsideration, we expect that TCC will challenge certain of the PUCT's rulings through appeals to Texas state and federal courts. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In TCC's final true-up order, the PUCT reduced net stranded generation costs by $51 million related to the present value of Accumulated Deferred Investment Tax Credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions. Also included in the final true-up order was language whereby the PUCT agreed to consider revisiting this issue if the Internal Revenue Service (IRS) ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. With the agreement in effect, as well as our ability to ultimately appeal the final true-up order, management does not believe a normalization violation has occurred. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table.

The IRS issued proposed regulations in March 2003 that would have liberalized the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS had not issued final regulations, TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. In December 2005, the IRS withdrew these previously proposed regulations and issued new proposed regulations. The new proposed regulations removed the retroactive election that allowed utilities, which were deregulated before March 4, 2003, to pass the benefits of ADITC and EDFIT back to ratepayers. The PUCT computation is premised on the withdrawn proposed regulations and may not be acceptable to the IRS under the new proposed regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of December 31, 2005 and also a loss of the ability to elect accelerated tax depreciation in the future. In light of the new proposed regulations, we are unable to predict how the IRS will ultimately rule on our private letter ruling request. However, prior precedent in this area would lead management to expect the IRS to rule that the PUCT approach of reducing the stranded cost recovery by the present value of its ADITC and EDFIT would, if ultimately imposed by a final, nonappealable order, constitute a normalization violation. Management intends to update the private letter ruling request for the new proposed regulations and issuance of the final order and will continue to work closely with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

Excess Earnings

The Texas Restructuring Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce transmission and distribution capital expenditures. Management believes excess earnings for TNC and SWEPCo are not true-up items. However, in January 2005, intervenors filed testimony in TNC's True-up Proceeding recommending that TNC's excess earnings be increased by approximately $5 million to reflect carrying charges on its excess earnings for the period from January 1, 2002 to March 2005. In addition, intervenors also recommended that TNC's transmission and distribution rates should be reduced by a maximum amount of approximately $3 million on an annual basis related to excess earnings. The PUCT did not address the excess earnings in the final true-up order, and instead required that excess earnings be addressed in TNC's Competition Transition Charge (CTC) filing. TNC's CTC filing was made in August 2005. As noted below, this filing has been suspended until further notice.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduced cash flows over the refund period. Through the end of 2004, TCC had refunded all but $10 million of its excess earnings liability. During 2005, TCC refunded an additional $9 million reducing its unrefunded excess earnings to $1 million. In July 2005, the PUCT approved a preliminary order in TCC's True-up Proceeding that instructed TCC to stop refunding the excess earnings and to offset the remaining balance, which was $1 million, against net stranded generation costs. In the final true-up order, the PUCT has utilized $1 million as a reduction to TCC's net stranded generation costs. However, prior to the final true-up order, in September 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings was unlawful under the Texas Restructuring Legislation. The decision stated that the excess earnings should have been treated as a reduction of stranded costs. As such, in September 2005, TCC recorded a regulatory asset of $56 million (including $7 million of interest) for the future recovery of the $49 million refunded to the REPs and a reduction to net stranded plant regulatory assets of $49 million, which also reduced the amount of carrying costs on TCC's books by $9 million. The PUCT filed a petition with the Texas Supreme Court to review the Texas Court of Appeals' decision. Management is unable to predict the ultimate outcome of these proceedings.

Wholesale Capacity Auction True-up and Stranded Plant Cost

The Texas Restructuring Legislation required that electric utilities and their affiliated power generation companies (PGCs) offer for sale at auction in 2002, 2003 and thereafter, at least 15% of the PGCs' Texas jurisdictional installed generation capacity. According to the legislation, the actual market power prices received in the state-mandated auctions are used to calculate wholesale capacity auction true-up revenues for recovery in the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. Based on its auction prices, TCC recorded a regulatory asset of $483 million in those years. TCC also recorded $126 million of carrying costs related to the wholesale capacity auction true-up, increasing the total asset to $609 million. As noted earlier, the PUCT ruled in the True-up Proceeding that TCC did not comply with the PUCT's rules regarding the auction of 15% of its Texas jurisdictional installed generation capacity. Based upon this ruling, TCC's capacity auction revenues were computed at higher nonauction prices and, as a result, TCC wrote off $422 million of its recorded regulatory asset and $110 million of related carrying costs. At December 31, 2005, TCC has a net true-up recoverable asset related to the wholesale capacity auction true-up of $77 million inclusive of remaining carrying costs.

In a nonaffiliated company's order, the PUCT also reduced that company's requested wholesale capacity auction true-up request. The PUCT determined that the nonaffiliated company had not met the PUCT's rules regarding the auction of 15% of its generation capacity because it failed to sell 15% of its generating capacity. That utility appealed the PUCT's decision to the Texas District Court. The District Court found that the PUCT erred by disallowing a significant portion of that utility's wholesale capacity auction true-up request. Although the facts regarding the nonaffiliated company's wholesale capacity auction true-up request and TCC's wholesale capacity auction true-up request are not exactly the same, management believes the District Court decision is a positive outcome and will prove to be beneficial to TCC's future claim that it is entitled to a significant portion, if not all, of TCC's requested amount.

In addition, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT then determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded plant cost balance that it determined was included in the capacity auction true-up. Since TCC had reduced its booked stranded cost regulatory asset by $238 million in December 2004 related to the duplicate depreciation, TCC increased its stranded plant cost regulatory asset by $206 million effectively adjusting its books to recognize the significantly lower $32 million net disallowance.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to their T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is referred to as the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In December 2003, the PUCT certified that the REPs in the TCC and TNC service territories had reached the 40% threshold for the small commercial class. At December 31, 2005, TCC's recorded retail clawback regulatory liability was $61 million and TNC's was $14 million. TCC recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $61 million, for the retail clawback liability. TNC received payment of $14 million from its nonaffiliated PTB REP in 2005, but has not refunded this money to its customers as of December 31, 2005. TNC's CTC proceeding, the proceeding that will determine the refund methodology, has been suspended. TCC received payment from its nonaffiliated REP in February 2006.

Fuel Balance Recoveries

In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred fuel balance for inclusion in their True-up Proceedings. The PUCT issued final orders in each of these proceedings that resulted in significant disallowances for both companies. Based upon these orders, TCC increased its over-recovered fuel balance by a total of $140 million, which resulted in a $209 million over-recovery liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed in the fourth quarter of 2005. TNC's under-recovered balance was adjusted by a total of $31 million. After the adjustments, TNC's under-recovered balance became an over-recovery of $5 million. Both TCC and TNC have challenged the PUCT's rulings regarding a number of issues in the fuel orders in federal and state court. Intervenors have also challenged certain rulings in the PUCT fuel order in state court.

In September 2005, the Texas District Court in Travis County issued a ruling which upheld the PUCT's decisions in the TNC proceeding. TNC and other parties have filed notice of appeal of that decision. TCC has not received a ruling from the Texas District Court regarding its appeal.

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the favorable federal TNC ruling is applicable to its appeal. The impact of the court order could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the Federal Court system, it could file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT is unsuccessful in its federal court appeal, TCC and TNC can reverse their provisions. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. This is because the ruling may result in a reallocation of off-system sales margins between AEP East companies and

AEP West companies. If that occurs, the AEP West companies would receive additional off-system sales margins from the AEP East companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the additional payments from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

In June 2004, the Texas Supreme Court determined that carrying costs should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and ordered that the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling became final.

In a nonaffiliated company's true-up order, the PUCT addressed the Supreme Court's remand decision and specified the manner in which carrying costs should be calculated. Based on this order, TCC first recorded carrying costs in 2004 and continued to accrue carrying costs in 2005. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. As a result, TCC recorded a $27 million reduction in its carrying costs in the first quarter of 2005 and reduced the amount of carrying costs accrued for the remainder of 2005. The PUCT indicated that it will address this retrospective ADFIT cost of money benefit in TCC's securitization proceeding.

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax cost of capital rate from its unbundled cost of service rate proceeding. The embedded debt component of the carrying cost rate is 8.12%. Based on the final order in TCC's True-up Proceeding, TCC reversed, in December 2005, $71 million of carrying costs, resulting in a net $19 million reduction in total carrying costs for 2005. Through December 2005, TCC recorded $283 million of carrying costs ($267 million on stranded generation plant costs and $16 million on wholesale capacity auction true-up). The remaining equity component of $153 million will be recognized in income as collected. TCC will continue to accrue a carrying cost.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% rate of return on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period regarding the rule. TCC received a final order (which is subject to rehearing) in the True-up Proceeding in February 2006. AEP will assert in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order.

The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until a final order is issued in TCC's True-up Proceeding. At that time, carrying costs accrue on the deferred fuel. For the retail clawback, carrying costs accrue when a final order is issued in TCC's True-up Proceeding.

TCC Securitization Proceeding

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge. The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an ADFIT benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

		in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	$	1,275
Unrecognized but Recoverable Equity Carrying Costs and Other		200
Estimated January 2006 – August 2006 Carrying Costs		144
Securitization Issuance Costs		24
Net Other Recoverable True-up Amounts (a)		161
Estimated Securitization Request	$	1,804

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

The final order did not address the allocation of stranded costs to TCC's wholesale jurisdiction which will be addressed in TCC's securitization proceeding. TCC estimates the amount allocated to wholesale to be less than $1 million. However, TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize.

TCC True-up Proceeding Summary

We believe that our recorded net true-up regulatory asset at December 31, 2005 of $1.3 billion accurately reflects the PUCT's final order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no additional impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding. If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

The Components of TNC's True-up Regulatory Liability as of December 31, 2005 and December 31, 2004 are:

	TNC			
	December 31, 2005		December 31, 2004	
	(in millions)			
Retail Clawback	$	(14)	$	(14)
Deferred Over-recovered Fuel Balance		(5)		(4)
Total Recorded Net True-up Regulatory Liability	$	(19)	$	(18)

TNC completed its True-up Proceeding in 2005 with the PUCT issuing a final order in May 2005. Based upon that final order, TNC adjusted its true-up regulatory liability. TNC filed a CTC proceeding in August 2005 to establish a rate to refund the net true-up regulatory liability. That filing has been suspended until the ruling from TNC's appeal to federal court regarding its final fuel reconciliation is fully resolved. This federal court ruling is discussed above. TNC accrues interest expense on the unrefunded balance and will continue accruing interest expense until the balance is fully refunded.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (Restructuring Act) provided for a Market Development Period (MDP) during which retail customers could choose their electric power suppliers or receive default service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and ended on December 31, 2005. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive default service, which must be offered by the incumbent utility at market rates. As of December 31, 2005, none of OPCo's customers have elected to choose an alternate power supplier and only a modest number of CSPCo's small commercial customers have switched suppliers.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. In February 2004, CSPCo and OPCo (the Ohio companies) filed Rate Stabilization Plans (RSP) with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers.

In January 2005, the PUCO approved the RSP for the Ohio companies. The approved plans provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues for specified costs. CSPCo's cost recovery under the Power Acquisition Rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding (see "Acquisitions" section of Note 10) will diminish CSPCo's potential for the additional annual 4% generation rate increases in 2006 by approximately one-half and to a lesser extent in 2007 and 2008. The plans also provide that the Ohio companies can recover in 2006, 2007 and 2008 environmental carrying costs and PJM-related administrative costs and congestion costs net of firm transmission rights (FTR) revenue from 2004 and 2005 related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $9 million for CSPCo and $47 million for OPCo in 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo related to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. In March 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSP and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. If the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo's and OPCo's future earnings will be adversely affected. In a nonaffiliated utility's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In addition, if the RSP order were determined on appeal to be illegal under the Restructuring Act, it would have an adverse effect on results of operations, cash flows and possibly financial condition. Although we believe that the RSP plan is legal and we intend to defend vigorously the PUCO's order, we cannot predict the ultimate outcome of the pending litigation.

In July 2005, CSPCo and OPCo each filed applications with the PUCO to decrease the transmission rates contained in their retail electric rates in order to reflect the FERC-approved OATT rate. Those applications were supplemented in December 2005 to update the proposed transmission rates to reflect the rates filed as part of a settlement agreement with the FERC (see "RTO Formation/Integration Costs" section of Note 4). As a result, annual transmission rates would be reduced by approximately $25 million. In accordance with the Restructuring Act, the Ohio companies also proposed to increase their distribution rates to fully offset the resulting decrease in their transmission rates. The PUCO approved these applications on December 28, 2005 and the new offsetting transmission and distribution rates became effective on that date. Under the terms of the PUCO's order in the RSP, the modified distribution rates in effect on December 31, 2005 are frozen though December 31, 2008 with certain exceptions, including governmentally-imposed changes resulting in increased distribution costs, changes in taxes or for major storm damage service restoration.

In September 2005, the Ohio companies filed with the PUCO to recover through a Transmission Cost Recovery Rider, beginning January 1, 2006, approximately $5 million for CSPCo and $7 million for OPCo of projected 2006 annual net costs incurred as a result of joining PJM. In addition, the Ohio companies requested to practice over/under-recovery deferral accounting for any differences between the revenues collected starting January 1, 2006 and the actual PJM costs incurred. In December 2005, the PUCO issued an order approving the rider components.

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month in which the Wyoming-Jacksons Ferry transmission line enters service in order to reflect their share of costs for that new line. We anticipate that, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing follows the settlement of our March 2005 filing with the FERC requesting increased OATT rates in which we received a three-step increase (see "FERC Order on Regional Through-and-out Rates and Mitigating SECA Revenue" section of Note 4).

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2005, we incurred $90 million of such costs and, accordingly, we deferred $43 million of such costs for probable future recovery in distribution rates. We have not yet recorded $7 million of equity carrying costs which are not recognized until collected. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2005, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2005 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the revised restructuring law, APCo is deferring incremental environmental generation costs for future recovery.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the West Virginia Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the West Virginia legislature made tax law changes necessary to preserve the revenues of state and local governments.

In 2001 through 2003, the West Virginia Legislature failed to enact the required tax legislation and the WVPSC closed its dockets. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCo's outside counsel advised that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCo's West Virginia generation business was no longer probable and operations in West Virginia met the requirements to reapply SFAS 71. Reapplying SFAS 71 in West Virginia had an insignificant effect on 2003 results of operations and financial condition.

7. <u>COMMITMENTS AND CONTINGENCIES</u>

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed component or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart Stations. Similar cases have been filed against other nonaffiliated utilities.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal has been appealed to the Second Circuit Court of Appeals and briefing continues. We believe the actions are without merit and intend to defend vigorously against the claims.

Ontario Litigation

In June 2005, we and several nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_X, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2005, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites. There are seven additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at seven sites under state law. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

NUCLEAR

Nuclear Plant

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant. The operation of a nuclear facility also involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

In 2005, the Price-Anderson Act was extended by amendment though December 31, 2025.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $236 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2005, funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $264 million are in external trust funds.

SNF Litigation

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. The DOE failed to begin accepting SNF by the January 1998 deadline in the law. DOE continues to fail the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, we, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability.

The case was tried in March 2004 on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, we appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied our pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that we may recover our post-breach damages in later suits as the costs are incurred.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. After expiration of the licenses, the Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low-level radioactive waste accumulation disposal costs for the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant was $27 million in 2005, 2004 and 2003.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2005 and 2004 and $12 million in 2003 related to special regulatory commission approved funding for decommissioning of the Cook Plant. At December 31, 2005, the total decommissioning trust fund balance for Cook Plant was $870 million. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs for the Cook Pla[illegible] including interest, unrealized gains and losses and expenses of the trust funds, increase or decrease the recor[illegible] liability.

Estimates from the decommissioning study could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M will work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, our future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. Aggregate construction expenditures for 2006 for consolidated operations are estimated to be $3.7 billion. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2021. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility and TEM Litigation

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. The initial term of our lease with Juniper (Juniper Lease) terminates on June 17, 2009. We may extend the term of the Juniper Lease to a total lease term of 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our Consolidated Balance Sheets and the obligations under the lease agreement are excluded from the table of future minimum lease payment in Note 16.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility. The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

We have the right to purchase the Facility for the acquisition cost during the last month of the Juniper Lease's initial term or on any monthly rent payment date during any extended term of the lease. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to a nonaffiliated third party. A purchase of the Facility from Juniper by us should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow as described below. If the Juniper Lease is renewed for up to a 30-year lease term, then at the end of that 30-year term we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $415 million) to Juniper for the excess of Juniper's acquisition cost over the proceeds from the sale. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report Juniper's funded obligations related to the Facility on our Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

Juniper's acquisition costs for the Facility totaled approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR (plus a component for a fixed-rate return on Juniper's equity investment and an administrative charge). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $33 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (4.53% at December 31, 2005). Annual sublease payments received from Dow are approximately $36 million (substantially based on an adjusted three-month LIBOR rate discussed above).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA was terminated and (iii) would be pursuing against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (i) award a termination payment to us under the terms of the PPA; (ii) grant our attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found to be unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to properly explain how the June 15, 2000 merger of AEP with CSW met the requirements of the PUHCA and sent the case back to the SEC for further review. Upon repeal of the PUHCA on February 8, 2006, we received a letter from the SEC, which dismissed the proceeding challenging our merger with CSW.

Enron Bankruptcy

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

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim sought to unwind the effects of the transaction. In December 2005, the parties reached a settlement resulting in a pretax cost of approximately $46 million.

Enron Bankruptcy – Summary – The amount expensed in current and prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities, the settlement agreement and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We have filed a Motion to Dismiss these actions, which the Court denied. We filed a Motion to Strike Class Action Allegations and to Stay Further Merits Discovery Pending Resolution of Class Certification Issues. The cases are in the discovery stage. We intend to continue to defend vigorously against these claims.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases have appealed the decisions. We will continue to defend vigorously each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies, including AEP and AEPES, making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases have been consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the court granted the plaintiffs motion for class certification. The defendants have filed a petition for leave to appeal this decision. We intend to continue to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, ERCOT and a number of nonaffiliated energy companies. The action alleged violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleged that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced TCE into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleged over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. The Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision and the appellate court affirmed the lower court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court, which was denied in January 2006. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. In December 2005, the federal court dismissed the plaintiffs' federal claims with prejudice and dismissed their state law claims without prejudice. After that decision, we settled all claims with plaintiffs in a settlement, subject to a confidentiality clause, and without material impact on results of operations or financial condition.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and continued to respond to supplemental data requests from some of these agencies in 2003 and 2004.

In September 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC sought civil penalties, restitution and disgorgement of benefits. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities, these being all agencies known still to be investigating these matters as to AEP. Our settlements did not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made settlement payments to the agencies in the first quarter of 2005 in accordance with the respective contractual terms. The agencies ended their investigations and the CFTC litigation filed in September 2003 also ended. During 2003 and 2004, we provided for the settlements payment in the amounts of $45 million and $36 million (nondeductible for federal income tax purposes), respectively. There was no impact on 2005 results of operations as a result of these investigations and settlements.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts. We claimed that BOM owed us at least $41 million related to previously recorded receivables on which we held approximately $20 million of credit collateral. In September 2005, we reached a settlement with BOM, subject to a confidentiality clause, without material impact on results of operations or financial condition.

FERC Long-term Contracts

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

8. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2005, the maximum future payments for all the LOCs are approximately $130 million with maturities ranging from February 2006 to March 2007. $58 million of this relates to our international power plant equity investment, which was sold in February 2006.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $53 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

Effective July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine. After consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2005, 2004 and 2003, we entered into several sale agreements. The status of certain sales agreements is discussed in the "Dispositions" section of Note 10. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.2 billion, $1 billion of which expired in January 2006. There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2005, the maximum potential loss for these lease agreements was approximately $54 million ($35 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 for disclosure of other lease residual value guarantees.

9. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As result of a 2005 company-wide staffing and budget review, approximately 500 positions were identified for elimination. Pretax severance benefits expense of $28 million was recorded (primarily in Maintenance and Other Operation) in 2005. Approximately 95% of the expense was within the Utility Operations segment. The following table shows the total 2005 expense recorded and the remaining accrual (reflected primarily in Current Liabilities – Other) as of December 31, 2005:

	Amount (in millions)
Total Expense	$ 28
Less: Total Payments	16
Remaining Accrual at December 31, 2005	$ 12

The remaining accrual is expected to be settled by the end of the second quarter of 2006, when severance efforts are scheduled to cease.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND OTHER LOSSES

ACQUISITIONS

2005

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of its customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia. This transaction was completed in December 2005 for $100 million.

DISPOSITIONS

2005

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (Investments – Other segment)

In November 2000, AEP made its initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. AEP Investments, Inc. (AEP Investments) sold approximately 2.1 million shares (71% of its investment in ICE) and recognized a $47 million pretax gain ($30 million, net of tax). AEP Investments' remaining fair value investment in ICE securities at December 31, 2005, classified as available for sale, is $31 million and AEP Investments is restricted from selling the remaining 0.9 million shares until May 2006.

Houston Pipe Line Company (HPL) (Investments – Gas Operations segment)

HPL owns, or leases, and operates natural gas gathering, transportation and storage operations in Texas. In 2003, management announced that we were in the process of divesting our noncore assets, which includes the assets within our Investments - Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted, net of tax cash flow analysis of the fair value of HPL, we recorded a pretax impairment of $300 million ($218 million, net of tax). This impairment included a pretax impairment of $150 million related to goodwill, reflecting management's decision not to operate HPL as a major trading hub. The cash flow analysis used management's estimate of the alternative likely outcomes of the uncertainties surrounding the continued use of the Bammel facility and other matters (see "Enron Bankruptcy" section of Note 7) and a net-of-tax, risk-free discount rate of 3.3% over the remaining life of the assets.

We also recorded a pretax charge of $15 million ($10 million, net of tax) in the fourth quarter of 2003. This charge related to the effect of the write-off of certain HPL and LIG assets and the impairment of goodwill related to our former optimization strategy of LIG assets by AEP Energy Services.

The total HPL pretax impairment of $315 million in 2003 is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In January 2005, we sold a 98% controlling interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL at that time and provided certain transitional administrative services to the buyer. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we have recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of December 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Consolidated Balance Sheets. The deferred gain was decreased in November 2005 by a $3 million payment related to purchase price true-up adjustments as defined in the contract. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see "Enron Bankruptcy – Right to use of cushion gas agreements" section of Note 7). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, the Company continues to hold forward gas contracts not sold with the gas pipeline and storage assets.

On November 14, 2005, we exercised a put option which allowed us to sell our remaining 2% interest to the buyer for approximately $17 million, which increased the deferred gain by approximately $8 million.

Pacific Hydro Limited (Investments – Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated in July 2005 and we recognized a pretax gain of $56 million. This gain is classified as Gain on Disposition of Equity Investments, Net on our 2005 Consolidated Statement of Operations.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement.

There had been an ongoing dispute between AEP and Centrica related to the ESM calculation. In March 2005, AEP and Centrica entered into a series of agreements resulting in the resolution of open issues related to the sale and the disputed ESM payments for 2003 and 2004. Also in March 2005, we received payments related to the ESM payments of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005, which is reflected in Gain/Loss on Disposition of Assets, Net on our accompanying Consolidated Statements of Operations. The ESM payments are contingent on Centrica's future operating results and are capped at $70 million and $20 million for 2005 and 2006, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System which included all of the generation facilities owned by our Registrant Subsidiaries. TCC's assets and liabilities related to STP were classified as Assets Held for Sale and Liabilities Held for Sale, respectively, on our Consolidated Balance Sheet as of December 31, 2004.

<u>2004</u>

Pushan Power Plant (Investments – Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. A purchase and sale agreement was signed in the fourth quarter of 2003. The sale was completed in March 2004 for $61 million. An estimated pretax loss on disposal of $20 million ($13 million, net of tax) was recorded in December 2002, based on an indicative price expression at that time, and was classified in Discontinued Operations. The effect of the sale on our 2004 results of operations was not significant. Results of operations of Pushan have been classified as Discontinued Operations in our Consolidated Statements of Operations. See "Discontinued Operations" section of this note for additional information.

LIG Pipeline Company and its Subsidiaries (Investments – Gas Operations segment)

As a result of our 2003 decision to exit our noncore businesses, we actively marketed LIG Pipeline Company, which had approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana, and five gas processing facilities that straddle the system. After receiving and analyzing initial bids during the fourth quarter of 2003, we recorded a pretax impairment loss of $134 million ($99 million, net of tax); of this pretax loss, $129 million related to the impairment of goodwill and $5 million related to other charges. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. (See "Jefferson Island Storage & Hub, LLC" section of this note for further information.) In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76 million was completed in April 2004 and the impact on results of operations in 2004 was not significant. The results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations on our Consolidated Statements of Operations. See "Discontinued Operations" section of this note for additional information.

Jefferson Island Storage & Hub, LLC (Investments – Gas Operations segment)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, LLC (JISH). The sale of JISH and its assets for $90 million was completed in October 2004. The sale resulted in a pretax loss of $12 million ($2 million, net of tax). The results of operations and loss on sale of JISH are classified as Discontinued Operations on our Consolidated Statements of Operations. See "Discontinued Operations" section of this note for additional information.

AEP Coal, Inc. (Investments – Other segment)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal, Inc." During 2002, the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production was expected to continue below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pretax impairment loss of $60 million including a goodwill impairment of $4 million.

In 2003, as a result of management's decision to exit our noncore businesses, we retained an advisor to facilitate the sale of AEP Coal, Inc. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a pretax charge of $67 million ($44 million, net of tax) comprised of a $30 million asset impairment, a $25 million charge related to accelerated remediation cost accruals and a $12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses are included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal, Inc. We received approximately $9 million cash and the buyer assumed an additional $11 million in future reclamation liabilities. We retained an estimated $37 million in future reclamation liabilities. The sale closed in April 2004 and the effect of the sale on our 2004 results of operations was not significant.

Independent Power Producers (Investments – Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). Our two Colorado investments included a 47.75% interest in Brush II, a 68-MW, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50% interest in Thermo, a 272-MW, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments included a 46.25% interest in Mulberry, a 120-MW, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50% interest in Orange, a 103-MW, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida. In accordance with GAAP, we were required to measure the impairment of each of these four investments individually. Based on indicative bids, it was determined that an other-than-temporary impairment existed on the two equity method investments located in Colorado. A pretax impairment of $70 million ($46 million, net of tax) was recorded in September 2003 as the result of the measurement of fair value that was triggered by our decision to sell these assets. This loss of investment value was included in Investment Value Losses on our 2004 Consolidated Statement of Operations.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a total sales price of $156 million, subject to closing adjustments. An additional pretax impairment of $2 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004. The sale resulted in a pretax gain of $105 million ($64 million, net of tax) generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded to Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Operations. The sale of the Ft. Lupton, Colorado plant closed in October 2004 and did not have a significant effect on our 2004 results of operations.

U.K. Generation (Investments – UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pretax impairment loss of $549 million ($414 million, net of tax).

In the fourth quarter of 2003, the U.K. generation plants were determined to be noncore assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. Based on bids received and other market information, we recorded a pretax charge of $577 million ($375 million, net of tax), including asset impairments of $421 million, during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional pretax charges of $156 million were also recorded in December 2003, including $122 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income (Loss) that were reclassified into earnings as a result of management's determination that the hedged event was no longer probable of occurring and $35 million related to a first quarter of 2004 sale of certain power contracts. All write-downs related to the U.K. that were booked in the fourth quarter of 2003 were included in Discontinued Operations on our 2003 Consolidated Statement of Operations.

In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge), related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pretax gain of $266 million ($128 million, net of tax). As a result of the sale, the buyer assumed an additional $46 million in future reclamation liabilities and $10 million in pension liabilities. The remaining assets and liabilities include certain physical power and capacity positions and financial coal and freight swaps. Substantially all of these positions matured or were settled with the applicable counterparties during 2005. The results of operations and gain on sale are included in Discontinued Operations on our Consolidated Statements of Operations for the year ended December 31, 2004. See "Discontinued Operations" section of this note for additional information.

Texas Plants – TCC and TNC Generation Assets (Utility Operations segment)

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability-must-run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel an RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to renew RMR contracts at the six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate the TNC plants, a pretax write-down of utility assets of $34 million was recorded during the third quarter of 2002. The decision to deactivate the TCC plants resulted in a pretax write-down of utility assets of approximately $96 million, which was deferred and recorded in Regulatory Assets in 2002.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional pretax asset impairment charge of $4 million in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of $3 million. Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets in 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in Regulatory Assets.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale on our Consolidated Balance Sheets. In accordance with the Texas Restructuring Legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which was expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding (see "Texas Restructuring" section of Note 6).

In March 2004, we signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on our 2004 results of operations.

The remaining generation assets and liabilities of TCC (TCC's interest in the Oklaunion plant) are classified as Assets Held for Sale and Liabilities Held for Sale, respectively, on our Consolidated Balance Sheets. See "Assets Held for Sale" section of this note for additional information.

South Coast Power Limited (Investments – Other Segment)

South Coast Power Limited (SCPL) is a 50% owned venture that was formed in 1996 to build, own and operate Shoreham Power Station, a 400-MW, combined-cycle, gas turbine power station located in Shoreham, England. In 2002, SCPL was subject to adverse wholesale electric power rates. A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pretax other-than-temporary impairment of the equity interest in the amount of $63 million.

In the fourth quarter of 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $47 million, resulting in a pretax gain of $48 million ($31 million, net of tax). The gain reflects improved conditions in the U.K. power market. This gain was recorded to Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Operations.

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began marketing an under-utilized office building in Dallas, Texas obtained through our merger with CSW in June 2000. One prospective buyer executed an option to purchase the building. The sale of the facility was projected by the second quarter of 2003 and an estimated 2002 pretax loss on disposal of $16 million was recorded, based on the option sale price. We recorded an additional pretax impairment of $6 million in Maintenance and Other Operation on our 2003 Consolidated Statement of Operations based on market data. The original prospective buyer did not complete their purchase of the building by the end of 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. An additional pretax impairment of $3 million was recorded in Maintenance and Other Operation expense during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building for $8 million. The sale did not have a significant effect on our results of operations.

Numanco LLC (Investments – Other segment)

In November 2004, we completed the sale of Numanco LLC for a sale price of $25 million. Numanco was a provider of staffing services to the utility industry. The sale did not have a significant effect on our 2004 results of operations.

2003

Mutual Energy Companies (Utility Operations segment)

On December 23, 2002, we sold the general partner interests and the limited partner interests in Mutual Energy CPL LP and Mutual Energy WTU LP for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. The buyer paid a base purchase price of $146 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a pretax gain of $129 million ($84 million, net of tax) during 2002. We provided the buyer with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. No revenue was recorded in 2004 and 2003 related to these sharing agreements, pending resolution of various contractual matters. Under the Texas Restructuring Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. We are responsible for a portion of such liability, if any, for the period we operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, we retained responsibility for regulatory obligations arising out of operations before closing. Our wholly-owned subsidiary, Mutual Energy Service Company LLC (MESC), received an up-front payment of approximately $30 million from the buyer associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC as of December 31, 2002 and were amortized over the two-year term of the back-office service agreement.

In February 2003, we completed the sale of MESC for $30 million dollars and realized a pretax gain of approximately $39 million, which included the recognition of the remaining balance of the original prepayment of $30 million ($27 million, net of tax), as no further service obligations existed for MESC. This gain was recorded in Gain/Loss on Disposition of Assets, Net on our Consolidated Statements of Operations.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for $38 million and recorded a pretax loss of $4 million in 2003 based upon final terms of the sale agreement. We had provided for a pretax charge of $7 million in 2002 based on an estimated sales price ($3 million asset impairment charge and $4 million lease prepayment penalty). We operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale.

Eastex (Investments – Other segment)

In 1998, we began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, we requested that the FERC allow us to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002, we solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. The estimated pretax loss on the sale of $219 million ($142 million, net of tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in discontinued operations during the fourth quarter of 2002.

We completed the sale of Eastex during 2003 and the effect of the sale on 2003 results of operations was not significant. The results of operations of Eastex were reclassified as Discontinued Operations in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," for all years presented. See the "Discontinued Operations" section of this note for additional information.

DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2005, 2004 and 2003. Results of operations of these businesses have been classified as shown in the following table (in millions):

	SEE-BOARD (a)	CitiPower	Eastex	Pushan Power Plant	LIG (b)(c)	U.K. Generation (c)	Total
2005 Revenue	$ 13	$ -	$ -	$ -	$ -	$ (7)	$ 6
2005 Pretax Income (Loss)	10	-	-	-	-	(13)	(3)
2005 Earnings (Loss), Net of Tax	24	-	-	-	5	(2)(d)	27
2004 Revenue	$ -	$ -	$ -	$ 10	$ 165	$ 125	$ 300
2004 Pretax Income (Loss)	(3)	-	-	9	(12)	164	158
2004 Earnings (Loss), Net of Tax	(2)	-	-	6	(12)	91(e)	83
2003 Revenue	$ -	$ -	$ 58	$ 60	$ 653	$ 125	$ 896
2003 Pretax Income (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss), Net of Tax	16	(13)	(14)	5	(91)	(508)(f)	(605)

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.
(c) 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.
(d) Earnings per share related to the UK Operations was $(0.01).
(e) Earnings per share related to the UK Operations was $0.23.
(f) Earnings per share related to the UK Operations was $(1.32).

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2005, AEP recorded pretax impairments of assets totaling $46 million ($39 million related to assets impairments and $7 million related to Investment Value Losses) that reflected our decision to retire two generation units and our decision to exit noncore businesses and other factors.

In 2004, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $18 million ($15 million related to Investment Value Losses, and $3 million related to charges recorded for excess real estate in Maintenance and Other Operation on the Consolidated Statement of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

In 2003, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $1.4 billion consisting of approximately $650 million related to Asset Impairments of $610 million and Other Related Charges of $40 million, $70 million related to Investment Value Losses, $711 million related to Discontinued Operations ($550 million of impairments and $161 million of other charges) and $6 million related to charges recorded for excess real estate in Maintenance and Other Operation on the 2003 Consolidated Statement of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

The categories of impairments and gains on dispositions include:

	2005	2004	2003
		(in millions)	
Asset Impairments and Other Related Charges (Pretax)			
AEP Coal, Inc.	$ -	$ -	$ 67
HPL and Other	-	-	315
Power Generation Facility	-	-	258
Blackhawk Coal Company	-	-	10
CSPCo's Conesville Units 1 and 2	39	-	-
Total	$ 39	$ -	$ 650
Investment Value Losses (Pretax)			
Independent Power Producers	$ -	$ (2)	$ (70)
Bajio	(7)	(13)	-
Total	$ (7)	$ (15)	$ (70)
Gain on Disposition of Equity Investments, Net			
Independent Power Producers	$ -	$ 105	$ -
South Coast Power Investment	-	48	-
Pacific Hydro Limited	56	-	-
Total	$ 56	$ 153	$ -
"Impairments and Other Related Charges" and "Operations" Included in Discontinued Operations (Net of Tax)			
Impairments and Other Related Charges:			
U.K. Generation Plants	$ -	$ -	$ (375)
Louisiana Intrastate Gas (a)	-	-	(99)
Total (b)	$ -	$ -	$ (474)
Operations:			
U.K. Generation Plants	$ (2)	$ 91	$ (133)
Louisiana Intrastate Gas (a)	5	(12)	8
CitiPower	-	-	(13)
Eastex	-	-	(14)
SEEBOARD	24	(2)	16
Pushan	-	6	5
Total	$ 27	$ 83	$ (131)
Total Discontinued Operations	$ 27	$ 83	$ (605)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub, LLC.
(b) See the "Dispositions" and "Discontinued Operations" sections of this note for the pretax impairment figures.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party requested that the court declare the co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of the unrelated party on October 10, 2005. TCC and the other nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. A decision by the Appeals Court is expected during the first half of 2006. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2005 and 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

The Assets Held for Sale and Liabilities Held for Sale at December 31, 2005 and 2004 are as follows:

Texas Plants	December 31, 2005	December 31, 2004
	(in millions)	
Assets:		
Other Current Assets	$ 1	$ 24
Property, Plant and Equipment, Net	43	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale	$ 44	$ 628
Liabilities:		
Regulatory Liabilities	$ -	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale	$ -	$ 250

OTHER LOSSES

2005

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following management's extensive review of the commercial viability of AEP's generation fleet, management committed to a plan to retire CSPCo's Conesville units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville units 1 and 2 were considered retired as of the third quarter of 2005.

A pretax charge of approximately $39 million was recognized in 2005 related to our decision to retire the units. The impairment amount is classified as Asset Impairments and Other Related Charges in our 2005 Consolidated Statement of Operations.

Compresion Bajio S de R.L. de C.V. (Investments – Other segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600-MW power plant in Mexico. A pretax other-than-temporary impairment charge of $13 million was recognized in December 2004 based on an indicative bid, which did not result in a sale.

In September 2005, a pretax other-than-temporary impairment charge of approximately $7 million was recognized based on an indicative offer received in September 2005. Both the 2005 and 2004 impairment amounts are classified as Investment Value Losses on our Consolidated Statements of Operations. The sale was completed in February 2006 without significant effect on our 2006 results of operations.

2003

Blackhawk Coal Company (Utility Operations segment)

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased operation due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a pretax charge of $10 million was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Asset Impairments and Other Related Charges on our 2003 Consolidated Statement of Operations.

Power Generation Facility (Investments – Other segment)

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We are currently subleasing the Facility to the Dow Chemical Company (Dow).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council Market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Subsequent litigation commenced between us and TEM.

The uncertainty of the litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power available for sale as a result of the TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a pretax impairment of $258 million ($168 million, net of tax) in December 2003. The impairment was recorded to Asset Impairments and Other Related Charges on our 2003 Consolidated Statement of Operations.

See further discussion in the "Power Generation Facility and TEM Litigation" section of Note 7.

11. BENEFIT PLANS

We sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit plans are sponsored by us to provide medical and life insurance benefits for retired employees. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004. The Medicare subsidy reduced our FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result of implementing FSP FAS 106-2, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2005, and a statement of the funded status as of December 31 for both years:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
		(in millions)		
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Service Cost	93	86	42	41
Interest Cost	228	228	107	117
Participant Contributions	-	-	20	18
Actuarial (Gain) Loss	191	379	(320)	(130)
Benefit Payments	(273)	(273)	(118)	(109)
Projected Obligation at December 31	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,555	$ 3,180	$ 1,093	$ 950
Actual Return on Plan Assets	224	409	70	98
Company Contributions	637	239	107	136
Participant Contributions	-	-	20	18
Benefit Payments	(273)	(273)	(118)	(109)
Fair Value of Plan Assets at December 31	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Funded Status:				
Funded Status at December 31	$ (204)	$ (553)	$ (659)	$ (1,007)
Unrecognized Net Transition Obligation	-	-	152	179
Unrecognized Prior Service Cost (Benefit)	(9)	(9)	5	5
Unrecognized Net Actuarial Loss	1,266	1,040	471	795
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

Amounts Recognized in the Balance Sheets as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
		(in millions)		
Prepaid Benefit Costs	$ 1,099	$ 524	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(31)	(28)
Additional Minimum Liability	(35)	(566)	N/A	N/A
Intangible Asset	6	36	N/A	N/A
Pretax Accumulated Other Comprehensive Income	29	530	N/A	N/A
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

N/A = Not Applicable

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category		(in percentage)	
Equity Securities	70	66	68
Debt Securities	28	25	25
Cash and Cash Equivalents	2	9	7
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2005 and 2004, and target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category		(in percentage)	
Equity Securities	66	68	70
Debt Securities	31	30	28
Other	3	2	2
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Because of the $320 million and $200 million contributions at the end of 2005 and 2004, respectively, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006 and January 2005.

The value of our pension plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The qualified plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits).

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

Accumulated Benefit Obligation	2005	2004
	(in millions)	
Qualified Pension Plans	$ 4,053	$ 3,918
Nonqualified Pension Plans	81	80
Total	$ 4,134	$ 3,998

Minimum Pension Liability

Our combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $204 million and $553 million at December 31, 2005 and 2004, respectively. For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2005 and 2004 were as follows:

	Underfunded Pension Plans	
	As of December 31,	
	2005	2004
	(in millions)	
Projected Benefit Obligation	$ 84	$ 2,978
Accumulated Benefit Obligation	81	2,880
Fair Value of Plan Assets	-	2,406
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	81	474

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

We made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet our goal of fully funding all qualified pension plans by the end 2005.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in percentages)			
Discount Rate	5.50	5.50	5.65	5.80
Rate of Compensation Increase	5.90 (a)	3.70	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The method used to determine the discount rate that we utilize for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, we changed to a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2005 and 2004 under this method was 5.50% for pension plans and 5.65% and 5.80%, respectively, for other postretirement benefit plans.

For 2005, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

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

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Required Contributions (a)	$ 8	$ 10	N/A	N/A
Additional Discretionary Contributions	-	626 (b)	$ 96	$ 107

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.
(b) Contribution in 2005 in excess of the required contribution to fully fund our qualified pension plans by the end of 2005.

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

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

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2006	$ 291	$ 117	$ (9)
2007	305	125	(10)
2008	316	133	(10)
2009	335	140	(11)
2010	344	148	(11)
Years 2011 to 2015, in Total	1,811	857	(65)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in millions)					
Service Cost	$ 93	$ 86	$ 80	$ 42	$ 41	$ 42
Interest Cost	228	228	233	107	117	130
Expected Return on Plan Assets	(314)	(292)	(318)	(92)	(81)	(64)
Amortization of Transition (Asset) Obligation	-	2	(8)	27	28	28
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	55	17	11	25	36	52
Net Periodic Benefit Cost (Credit)	61	40	(3)	109	141	188
Capitalized Portion	(17)	(10)	(3)	(33)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 44	$ 30	$ (6)	$ 76	$ 95	$ 145

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in percentage)					
Discount Rate	5.50	6.25	6.75	5.80	6.25	6.75
Expected Return on Plan Assets	8.75	8.75	9.00	8.37	8.35	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2005 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was 8.75% for 2005. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was increased to 8.37%.

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

Health Care Trend Rates:	2005	2004
Initial	9.0 %	10.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2009

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	263	(215)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. Our contributions to the plan are 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $57 million in 2005, $55 million in 2004 and $57 million in 2003.

Other UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2005, 2004 and 2003.

12. STOCK-BASED COMPENSATION

The Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was originally adopted by the Board of Directors and shareholders in 2000. The amended and restated version was adopted by the Board of Directors and shareholders in 2005.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance units and stock options. Our outstanding restricted stock units generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. We awarded 165,743, 105,852 and 105,910 restricted stock units, including units awarded for dividends, with weighted-average grant-date fair values of $35.67, $32.03 and $22.17 per unit in 2005, 2004 and 2003, respectively. Compensation cost is recorded over the vesting period based on the market value on the grant date. Expense associated with units that are forfeited is reversed in the period of forfeiture.

We awarded 300,000 restricted shares in 2004 that vest over periods ranging from one to eight years and we have not awarded any other restricted shares. Compensation cost is recorded over the vesting period based on the market value of $30.76 per unit on the grant date.

Performance units are generally equal in value to shares of AEP common stock except that the number of performance units held is multiplied by a performance factor which can range from 0% to 200% to determine the number of performance units realized. The performance factor is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee). Performance units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participant's AEP career (career shares). Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and phantom stock units accrue as additional units. We awarded 1,012,597, 119,000 and 1,066,198 performance units with grant-date fair values of $34.02, $30.76 and $28.02 per unit in 2005, 2004 and 2003, respectively. In addition, AEP awarded 89,138, 61,079 and 51,388 additional units as reinvested dividends on outstanding performance units and phantom stock units with weighted-average grant-date fair values of $36.25, $32.92 and $25.64 per unit in 2005, 2004 and 2003, respectively. In 2005, the HR Committee certified a performance factor of 123.1% for performance units originally granted for the December 10, 2003 through December 31, 2004 performance period. As a result, 946,789 performance units were deferred into phantom stock units, which will generally vest, subject to the participant's continued employment, on December 31, 2006. The performance factor was zero for all other performance periods that the HR Committee reviewed in 2005, 2004 and 2003. Therefore, no other performance units were earned or deferred into phantom stock units during these years.

The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and phantom stock units is adjusted for changes in fair market value.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant, and in accordance with APB 25, we do not record compensation expense. We adopted SFAS 123R effective January 1, 2006, which resulted in the recording of compensation expense for stock-based compensation (see "SFAS 123R" in section of Note 2). We historically granted options with a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.
A summary of AEP stock option transactions in fiscal years 2005, 2004 and 2003 is as follows:

	2005			2004			2003		
	Options (in thousands)		**Weighted Average Exercise Price**	**Options (in thousands)**		**Weighted Average Exercise Price**	**Options (in thousands)**		**Weighted Average Exercise Price**
Outstanding at beginning of year	8,230	$	33	9,095	$	33	8,787	$	34
Granted	10		39	149		31	928		28
Exercised	(1,886)		37	(525)		27	(23)		27
Forfeited	(132)		32	(489)		34	(597)		33
Outstanding at end of year	6,222		34	8,230		33	9,095		33
Options exercisable at end of year	5,199	$	35	6,069	$	35	3,909	$	36
Weighted average exercise price of options:									
Granted above Market Price			N/A			N/A			N/A
Granted at Market Price		$	39		$	31		$	28

The following table summarizes information about AEP stock options outstanding at December 31, 2005:

Options Outstanding

Range of Exercise Prices	**Number Outstanding** (in thousands)	**Weighted Average Remaining Life** (in years)		**Weighted Average Exercise Price**
$25.73 - $27.95	1,610	6.6	$	27.36
$30.76 - $38.65	4,140	3.9		35.45
$43.79 - $49.00	472	4.3		46.11
	6,222	4.6		34.16

Options Exercisable

Range of Exercise Prices	**Number Outstanding** (in thousands)		**Weighted Average Exercise Price**
$25.73 - $27.95	696	$	27.25
$30.76 - $35.63	4,031		35.56
$43.79 - $49.00	472		46.11
	5,199		35.40

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of AEP options granted:

	2005	2004	2003
Risk Free Interest Rate	4.14%	4.14%	3.92%
Expected Life	7 years	7 years	7 years
Expected Volatility	24.63%	28.17%	27.57%
Expected Dividend Yield	4.00%	4.84%	4.86%
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	N/A
Granted at Market Price	$ 7.60	$ 6.06	$ 5.26

13. BUSINESS SEGMENTS

We identify our reportable segments based on the nature of the product and services and geography. Our segments are organized based on the manner in which management makes operating decisions and assesses performance. Our core operations involve domestic utility operations, including generation, transmission and distribution of electric energy. Certain Investments segments are reported by product or service (Gas Operations and Other) while our Investments – UK Operations segment is distinguished by its geography.

In addition to our business operations with external customers, our business segments also provide products and services between business segments. These intersegment activities primarily consist of risk management activities and barging activities performed by our Utility Operations segment and the sale of gas by our Investments – Gas Operations segment. Our Investments – Other segment includes barging activities and, until the second quarter of 2004, the sale of coal to our Utility Operations segment. Our All Other segment includes items such as interest related to financing costs, litigation costs on behalf of other segments and other corporate-type services.

Our current international portfolio, presented in our Investments – Other segment, includes only a limited investment in the generation and supply of power in Mexico, which was sold in February 2006. We also sold our generation assets in the U.K. and China in 2004 and our generation assets in the Pacific Rim in 2005 (see "Dispositions" section of Note 10).

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- Operations of LIG, including Jefferson Island Storage & Hub, LLC, were classified as Discontinued Operations during 2003 and were sold during 2004. The remaining gas pipeline and storage assets were disposed of in 2005 with the sale of HPL (see "Dispositions" section of Note 10).

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.
- UK Operations were classified as Discontinued Operations during 2003 and were sold during 2004.

Investments – Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.
- Four IPPs were sold during 2004.

The tables below present segment income statement information for the twelve months ended December 31, 2005, 2004 and 2003 and balance sheet information for the years ended December 31, 2005 and 2004. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2005							
Revenues from:							
External Customers	$ 11,193	$ 463	$ -	$ 455	$ -	$ -	$ 12,111
Other Operating Segments	203	(181)	-	17	3	(42)	-
Total Revenues	$ 11,396	$ 282	$ -	$ 472	$ 3	$ (42)	$ 12,111
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,020	$ (31)	$ -	$ 93	$ (53)	$ -	$ 1,029
Discontinued Operations, Net of Tax	-	5	(2)	24	-	-	27
Extraordinary Loss, Net of Tax	(225)	-	-	-	-	-	(225)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	-	-	-	-	(17)
Net Income (Loss)	$ 778	$ (26)	$ (2)	$ 117	$ (53)	$ -	$ 814
Depreciation and Amortization Expense	$ 1,285	$ 2	$ -	$ 30	$ 1	$ -	$ 1,318
Gross Property Additions	2,755	2	-	7	-	-	2,764

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2004							
Revenues from:							
External Customers	$ 10,664	$ 3,068	$ -	$ 513	$ -	$ -	$ 14,245
Other Operating Segments	105	50	-	36	7	(198)	-
Total Revenues	$ 10,769	$ 3,118	$ -	$ 549	$ 7	$ (198)	$ 14,245
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,175	$ (51)	$ -	$ 74	$ (71)	$ -	$ 1,127
Discontinued Operations, Net of Tax	-	(12)	91	4	-	-	83
Extraordinary Loss, Net of Tax	(121)	-	-	-	-	-	(121)
Net Income (Loss)	$ 1,054	$ (63)	$ 91	$ 78	$ (71)	$ -	$ 1,089
Depreciation and Amortization Expense	$ 1,256	$ 11	$ -	$ 32	$ 1	$ -	$ 1,300
Gross Property Additions	1,471	132	-	34	-	-	1,637

2003	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 11,030	$ 3,100	$ -	$ 703	$ -	$ -	$ 14,833
Other Operating Segments	130	27	-	52	11	(220)	-
Total Revenues	$ 11,160	$ 3,127	$ -	$ 755	$ 11	$ (220)	$ 14,833
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,223	$ (290)	$ -	$ (282)	$ (129)	$ -	$ 522
Discontinued Operations, Net of Tax	-	(91)	(508)	(6)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	$ 1,459	$ (403)	$ (529)	$ (288)	$ (129)	$ -	$ 110
Depreciation and Amortization Expense	$ 1,250	$ 18	$ -	$ 39	$ -	$ -	$ 1,307
Gross Property Additions	1,288	24	-	10	-	-	1,322

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837
Total Property, Plant and Equipment – Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199(c)	$ 632(d)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	-	52	-	-	52
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,014	$ 445	$ -	$ 832	$ 3	$ -	$ 37,294
Accumulated Depreciation and Amortization	14,363	43	-	86	1	-	14,493
Total Property, Plant and Equipment – Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,148	1,789	221(e)	2,071	8,093	(9,686)	34,636
Assets Held for Sale	628	-	-	-	-	-	628
Investments in Equity Method Subsidiaries	-	33	-	117	-	-	150

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

(c) Total Assets of $1.2 billion for the Investments-Gas Operations segment include $429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.

(d) Total Assets of $632 million for the Investments-UK Operations segment include $613 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $19 million in assets represents cash equivalents with value-added tax receivables.

(e) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

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

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized on the accrual or settlement basis.

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

Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) until the period the hedged item affects earnings. We recognize any hedge ineffectiveness in earnings immediately during the period of change.

Fair Value Hedging Strategies

Prior to the sale of HPL in the first quarter of 2005, to hedge the risks associated with our domestic gas pipeline and storage activities, we entered into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of this hedging activity was to protect the natural gas inventory against changes in fair value due to changes in spot gas prices. The derivative contracts designated as fair value hedges of our natural gas inventory were MTM each month based upon changes in the NYMEX forward prices, whereas the natural gas inventory was MTM on a monthly basis based upon changes in the Gas Daily spot price at the end of the month. The differences between the indices used to MTM the natural gas inventory and the forward contracts designated as fair value hedges can result in volatility in our reported net income. However, over time gains or losses on the sale of the natural gas inventory will be offset by gains or losses on the fair value hedges, resulting in the realization of gross margin we anticipated at the time the transaction was structured. In the third quarter of 2004, the gas-related fair value hedges were de-designated. As a result, the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost. During 2005, 2004 and 2003, we recognized a pretax loss of approximately $0 million, $27.0 million and $3.4 million, respectively, in Revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. The interest rate swap transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged in Interest Expense. During 2005, 2004 and 2003, we recognized no hedge ineffectiveness related to these swaps.

Cash Flow Hedging Strategies

We may enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against foreign currencies, the decline in value of future foreign currency cash flows is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. The impact of these hedges, which is immaterial, is included in Operating Expenses. We do not hedge all foreign currency exposure.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate swap transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2005 and 2003, we reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, we reclassified an immaterial amount to earnings because the original forecasted transaction did not occur within the originally specified time period.

We enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative contracts to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2005, 2004 and 2003, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

We entered into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues. During 2005, 2004 and 2003, we recognized immaterial amounts in earnings related to hedge ineffectiveness. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2005 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
	(in millions)			
Power and Gas	$ 11	$ 20	$ (6)	$ (5)
Interest Rate	3	-	(21)(a)	(2)
	$ 14	$ 20	$ (27)	$ (7)

(a) Includes $1 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2004 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
	(in millions)			
Power and Gas	$ 88	$ (60)	$ 23	$ (26)
Interest Rate	1	(23)	(23)(a)	4
	$ 89	$ (83)	$ -	$ (22)

(a) Includes $3 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2005, the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows related to forecasted transactions is twelve months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2005:

	Amount
	(in millions)
Balance at December 31, 2002	$ (16)
Changes in fair value	(79)
Reclasses from AOCI to net earnings	1
Balance at December 31, 2003	(94)
Changes in fair value	8
Reclasses from AOCI to net earnings	86
Balance at December 31, 2004	-
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(22)
Ending Balance, December 31, 2005	$ (27)

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2005 and 2004 are summarized in the following tables.

	2005		2004	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 12,226	$ 12,416	$ 12,287	$ 12,813
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	-	66	67

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments which are classified as available for sale for decommissioning and SNF disposal, reported in Spent Nuclear Fuel and Decommissioning Trusts and Assets Held for Sale on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115. At December 31, 2005 and 2004, the fair values of the trust investments were $1.1 billion and $1.2 billion, respectively, and had a cost basis of $989 million and $1 billion, respectively. The change in market value in 2005, 2004 and 2003 was a net unrealized gain of $28 million, $41 million and $53 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary loss and cumulative effect of accounting changes as reported are as follows:

	Year Ended December 31,		
	2005	2004	2003
	(in millions)		
Federal:			
Current	$ 375	$ 262	$ 297
Deferred	28	263	34
Total	403	525	331
State and Local:			
Current	25	49	19
Deferred	4	(3)	1
Total	29	46	20
International:			
Current	(2)	1	7
Deferred	-	-	-
Total	(2)	1	7
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 430	$ 572	$ 358

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

	Year Ended December 31, 2005	2004	2003
		(in millions)	
Net Income	$ 814	$ 1,089	$ 110
Discontinued Operations (net of income tax of $(30) million, $75 million and $(312) million in 2005, 2004 and 2003, respectively)	(27)	(83)	605
Extraordinary Loss, (net of income tax of $(121) million and $(64) million in 2005 and 2004, respectively)	225	121	-
Cumulative Effect of Accounting Changes (net of income tax of $(9) million and $138 million in 2005 and 2003, respectively)	17	-	(193)
Preferred Stock Dividends	7	6	9
Income Before Preferred Stock Dividends of Subsidiaries	1,036	1,133	531
Income Taxes Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	430	572	358
Pretax Income	$ 1,466	$ 1,705	$ 889
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 513	$ 597	$ 311
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	39	36	34
Asset Impairments and Investment Value Losses	-	-	23
Investment Tax Credits (net)	(32)	(29)	(33)
Tax Effects of International Operations	(2)	1	8
Energy Production Credits	(18)	(16)	(15)
State Income Taxes	19	30	13
Removal Costs	(14)	(12)	(6)
AFUDC	(14)	(11)	(10)
Medicare Subsidy	(13)	(10)	-
Tax Reserve Adjustments	(11)	(14)	13
Other	(37)	-	20
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 430	$ 572	$ 358
Effective Income Tax Rate	29.3%	33.5%	40.3%

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

	As of December 31, 2005	2004
	(in millions)	
Deferred Tax Assets	$ 2,085	$ 2,280
Deferred Tax Liabilities	(6,895)	(7,099)
Net Deferred Tax Liabilities	$ (4,810)	$ (4,819)
Property Related Temporary Differences	$ (3,302)	$ (3,273)
Amounts Due From Customers For Future Federal Income Taxes	(186)	(184)
Deferred State Income Taxes	(384)	(452)
Transition Regulatory Assets	(176)	(211)
Securitized Transition Assets	(232)	(258)
Regulatory Assets	(446)	(578)
Accrued Pensions	(345)	(158)
Deferred Income Taxes on Other Comprehensive Loss	14	186
All Other (net)	247	109
Net Deferred Tax Liabilities	$ (4,810)	$ (4,819)

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current 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 IRS and other taxing authorities routinely examine our tax returns. Management believes that we have filed tax returns with positions that may be challenged by these tax authorities. These positions relate to, among others, the federal treatment of taxes paid to foreign taxing authorities (the most significant of which is the federal treatment of the U.K. Windfall Profits Tax), the timing and amount of deductions and the tax treatment related to acquisitions and divestitures. We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. CSW, which was a separate consolidated group prior to its merger with AEP, is currently being audited for the years 1997 through the date of merger in June 2000. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2005, the Company has total provisions for uncertain tax positions of approximately $136 million. In addition, the Company accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

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

On August 8, 2005 the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of Integrated Gasification Combined Cycle (IGCC) plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP has announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. The United States Treasury Department was to announce by February 6, 2006 the program whereby taxpayers could apply for and be allocated these credits. The Treasury Department has yet to define its program. We cannot predict if AEP will be allocated any of these tax credits.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over 84-months in lieu of taking a depreciation deduction over 20-years. This act also allows for the transfer ("poured-over") of funds held in non-qualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the non-qualified funds are poured-over; the funds are poured-over over the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for non-qualified funds. We believe that the tax law changes discussed in this paragraph will not materially affect our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. We believe that the application of these tax acts will not materially affect our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of $83 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $22 million.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 was approximately $2 million.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance policies; all of which will not have a material impact on future results of operations and cash flows.

16. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Maintenance and Other Operation in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31, 2005	2004	2003
		(in millions)	
Lease Payments on Operating Leases	$ 307	$ 317	$ 344
Amortization of Capital Leases	57	54	64
Interest on Capital Leases	13	11	9
Total Lease Rental Costs	$ 377	$ 382	$ 417

Property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets are as follows:

	December 31, 2005	December 31, 2004
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 95	$ 91
Distribution	15	15
Other	331	323
Total Property, Plant and Equipment Under Capital Leases	441	429
Accumulated Amortization	190	186
Net Property, Plant and Equipment Under Capital Leases	$ 251	$ 243
Obligations Under Capital Leases		
Noncurrent Liability	$ 193	$ 190
Liability Due Within One Year	58	53
Total Obligations Under Capital Leases	$ 251	$ 243

Future minimum lease payments consisted of the following at December 31, 2005:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2006	$ 73	$ 313
2007	68	288
2008	45	264
2009	29	251
2010	16	249
Later Years	93	2,018
Total Future Minimum Lease Payments	$ 324	$ 3,383
Less Estimated Interest Element	73	
Estimated Present Value of Future Minimum Lease Payments	$ 251	

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct, own and lease the Gavin Scrubber for the Gavin Plant to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($470 million). Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for as an operating lease with a nonaffiliated third party. For the first half of 2003, operating lease payments related to the Gavin Scrubber were recorded as operating lease expense by OPCo. In our 2003 Consolidated Statement of Operations, these lease payments are included in Maintenance and Other Operation. After July 1, 2003, OPCo has recorded the depreciation, interest and other operating expenses of JMG and has eliminated JMG's rental revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of the requirement to consolidate JMG and there was no change in net income due to the consolidation of JMG. The debt obligations of JMG are now included in Long-term Debt as Notes Payable and Installment Purchase Contracts and are excluded from the above table of future minimum lease payments.

At any time during the obligation, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year term is noncancelable. At the end of the initial term, OPCo can renew the obligation, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In the case of a sale at less than the adjusted acquisition cost, OPCo is required pay the difference to JMG.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each company as of December 31, 2005 are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payments included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2005, the maximum potential loss was approximately $31 million ($20 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Common Stock

2005

Common Stock Repurchase

In February 2005, our Board of Directors authorized the repurchase up to $500 million of our common stock from time to time through 2006. In March 2005, we purchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged $34.18 per share. Management has not established a timeline for the buyback of the remaining stock under this plan.

Equity Units and Remarketing of Senior Notes

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consisted of a forward purchase contract and a senior note. In June 2005, we remarketed and settled $345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes mature on August 16, 2007. We did not receive any proceeds from the mandatory remarketing.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for $50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 1, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

2003

In 2003, we issued 56 million shares and received net proceeds of $1.1 billion.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2005, 2004 and 2003:

Shares of Common Stock	Issued	Held in Treasury
Balance January 1, 2003	347,835,212	8,999,992
Issued	56,181,201	-
Treasury stock:		
Acquisition	-	-
Retirement	-	-
Balance December 31, 2003	404,016,413	8,999,992
Issued	841,732	-
Treasury stock:		
Acquisition	-	-
Retirement	-	-
Balance December 31, 2004	404,858,145	8,999,992
Issued	10,360,685	-
Treasury stock:		
Acquisition	-	12,500,000
Retirement	-	-
Balance December 31, 2005	415,218,830	21,499,992

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2005			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,642	$ 61

	December 31, 2004			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,662	$ 61
Subject to Mandatory Redemption:				
5.90% (c)	$100	850,000	182,000	18
6.25% - 6.875% (c)	$100	950,000	482,450	48
Total Subject to Mandatory Redemption (c)				66
Total Preferred Stock				$ 127

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.
(b) As of December 31, 2005, the subsidiaries had 14,487,597 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2004, the subsidiaries had 13,823,127 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued.
(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds (generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed.
(d) The number of shares of preferred stock redeemed is 664,470 shares in 2005, 96,378 shares in 2004 and 86,210 shares in 2003.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2005	Interest Rate Range at December 31, 2005	2004	December 31, 2005	2004
				(in millions)	
INSTALLMENT PURCHASE CONTRACTS (a)					
2006-2009	3.99%	2.70%-4.55%	1.75%-4.55%	$ 163	$ 163
2011-2022	4.14%	2.625%-6.10%	1.70%-6.10%	785	785
2023-2038	3.91%	2.625%-6.55%	1.125%-6.55%	987	825
SENIOR UNSECURED NOTES					
2005-2009	5.49%	3.60%-6.91%	2.879%-6.91%	1,973	3,459
2010-2017	5.21%	4.40%-6.375%	4.40%-6.375%	3,783	2,633
2032-2035	6.21%	5.625%-6.65%	5.625%-6.65%	2,125	1,625
FIRST MORTGAGE BONDS (b)					
2005-2008 (c)	6.93%	6.20%-7.75%	6.20%-8.00%	222	456
2025	-	-	8.00%	-	45
NOTES PAYABLE (d)					
2006-2017	6.08%	4.47%-15.25%	2.325%-15.25%	904	939
SECURITIZATION BONDS					
2007-2017	5.78%	5.01%-6.25%	3.54%-6.25%	648	698
NOTES PAYABLE TO TRUST					
2043	5.25%	5.25%	5.25%	113	113
EQUITY UNIT SENIOR NOTES					
2007	4.709%	4.709%	5.75%	345	345
OTHER LONG-TERM DEBT (e)				236	243
Equity Unit Contract Adjustment Payments				-	9
Unamortized Discount (net)				(58)	(51)
Total Long-term Debt Outstanding				12,226	12,287
Less Portion Due Within One Year				1,153	1,279
Long-term Portion				$ 11,073	$ 11,008

(a) For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.

(b) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment. There are certain limitations on establishing additional liens against our assets under our indentures.

(c) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had balances of $18 million and $84 million in 2005 and 2004, respectively. Trust fund assets related to this obligation of $2 million and $72 million are included in Other Temporary Cash Investments and $21 million and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2005 and 2004, respectively. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond has a balance of $8 million at December 31, 2005. Trust fund assets related to this obligation of $1 million are included in Other Temporary Cash Investments and $8 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2005. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(d) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(e) Other long-term debt consists of fair market value of adjustments of fixed rate debt that is hedged, a liability along with accrued interest for disposal of spent nuclear fuel (see "Nuclear" section of Note 7) and a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2005 IS PAYABLE AS FOLLOWS:

	2006	2007	2008	2009	2010	After 2010	Total
				(in millions)			
Principal Amount	$ 1,153	$ 1,243	$ 575	$ 927	$ 1,224	$ 7,162	$ 12,284
Unamortized Discount							(58)
							$ 12,226

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

Trust Preferred Securities

SWEPCO has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. In addition, PSO and TCC had trusts that were deconsolidated in 2003 due to the implementation of FIN 46. The Junior Subordinated Debentures held in the trust for PSO and TCC were retired in 2004. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2005 and 2004, is included in Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2005 and 2004, are reported as Notes Payable to Trust within Long-term Debt.

The business trust is treated as a nonconsolidated subsidiary of its parent company. The only asset of the business trust is the subordinated debentures issued by its parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that held the assets of HPL and LIG. Caddis was capitalized with $2 million cash from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a noncontrolling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead was an unconsolidated special purpose entity whose investors had no relationship to us or any of our subsidiaries. The money invested in Caddis by Steelhead was loaned to SubOne.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis. As a result, a note payable ($533 million) to Caddis was reported as a component of Long-term Debt on July 1, 2003, the balance of which was $0 on December 31, 2005 and 2004. Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

Lines of Credit – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. As of December 31, 2005, our commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%. In September 2005, Moody's Investors Service upgraded AEP's commercial paper rating to Prime-2 from Prime-3.

At December 31, 2005 and 2004, we had $10 million and $23 million, respectively, in outstanding commercial paper related to JMG, reflected as Short-term Debt on our Consolidated Balance Sheets. This interest rate of the JMG commercial paper at December 31, 2005 and 2004 was 4.47% and 2.50%, respectively. This commercial paper is specifically associated with the Gavin Scrubber as identified in the "Gavin Scrubber Financing Arrangement" section of Note 16 and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate its cash collections.

AEP Credit's sale of receivables agreement expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2005	Year Ended December 31, 2004
	($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,925	$ 5,163
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 106	$ 80
Deferred Revenue from Servicing Accounts Receivable	$ 1	$ 1
Loss on Sale of Accounts Receivable	$ 18	$ 7
Average Variable Discount Rate	3.23%	1.50%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	$ 103	$ 78
Retained Interest if 20% Adverse Change in Uncollectible Accounts	$ 101	$ 76

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2005	2004
	(in millions)	
Customer Accounts Receivable Retained	$ 826	$ 830
Accrued Unbilled Revenues Retained	374	665
Miscellaneous Accounts Receivable Retained	51	84
Allowance for Uncollectible Accounts Retained	(31)	(77)
Total Net Balance Sheet Accounts Receivable	1,220	1,502
Customer Accounts Receivable Securitized	516	435
Total Accounts Receivable Managed	$ 1,736	$ 1,937
Net Uncollectible Accounts Written Off	$ 74	$ 86

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $30 million and $25 million at December 31, 2005 and 2004, respectively.

18. JOINTLY-OWNED ELECTRIC UTILITY PLANT

We have generating units that are jointly-owned with nonaffiliated companies. We are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Statements of Operations and the investments are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

		Company's Share December 31, 2005		2004	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in millions)			
W.C. Beckjord Generating Station (Unit No. 6)	12.5%	$ 16	$ -	$ 16	$ -
Conesville Generating Station (Unit No. 4)	43.5	85	8	85	1
J.M. Stuart Generating Station	26.0	266	35	210	61
Wm. H. Zimmer Generating Station	25.4	749	2	741	8
Dolet Hills Generating Station (Unit No. 1)	40.2	238	4	238	3
Flint Creek Generating Station (Unit No. 1)	50.0	94	2	94	1
Pirkey Generating Station (Unit No. 1)	85.9	460	10	457	2
STP Generation Station (Units No. 1 and 2) (a)	0.0	-	-	2,387	2
Oklaunion Generating Station (Unit No. 1) (b)	78.1	415	3	412	2
Transmission	(c)	63	1	62	4

(a) Included in Assets Held for Sale on our Consolidated Balance Sheets. Sale of STP was completed in May 2005. We owned 25.2% of STP at December 31, 2004.

(b) TCC's 7.8% interest in Oklaunion amounted to $39,977 and $39,735 at December 31, 2005 and 2004. These amounts are included in Assets Held for Sale on our Consolidated Balance Sheets.

(c) Varying percentages of ownership.

The amount of accumulated depreciation related to our share of jointly-owned facilities is $1.2 billion and $2.1 billion at December 31, 2005 and 2004, respectively. Of these amounts, $20 million and $991 million is included in Assets Held for Sale on our Consolidated Balance Sheets at December 31, 2005 and 2004, respectively. The remainder is included in Accumulated Depreciation and Amortization.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

(In Millions – Except Per Share Amounts)	2005 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 3,065	$ 2,819	$ 3,328	$ 2,899
Operating Income	660	455	624	188
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	351	221	365	92
Extraordinary Loss, Net of Tax (a)	-	-	-	(225)
Net Income (Loss)	355	221	387	(149)
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share	0.90	0.58	0.99	(0.38)
Diluted Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (c)	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share (d)	0.90	0.58	0.99	(0.38)

(In Millions – Except Per Share Amounts)	2004 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 3,404	$ 3,457	$ 3,819	$ 3,565
Operating Income	634	420	644	285
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	289	151	412	275
Extraordinary Loss, Net of Tax (a)	-	-	-	(121)
Net Income	282	100	530	177
Basic and Diluted Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (e)	0.73	0.38	1.04	0.69
Basic and Diluted Extraordinary Loss per Share	-	-	-	(0.31)
Basic and Diluted Earnings per Share	0.71	0.25	1.34	0.45

(a) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarters of 2005 and 2004.
(b) Amounts for 2005 do not add to $(0.58) for Extraordinary Loss per Share due to differences between the weighted average number of shares outstanding for the fourth quarter of 2005 and the year 2005.
(c) Amounts for 2005 do not add to $2.63 for Diluted Earnings (Loss) per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.
(d) Amounts for 2005 do not add to $2.08 for Diluted Earnings (Loss) per Share due to rounding.
(e) Amounts for 2004 do not add to $2.85 for Basic and Diluted Earnings per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.

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AEP GENERATING COMPANY

AEP GENERATING COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 270,755	$ 241,788	$ 233,165	$ 213,281	$ 227,548
Operating Income	$ 10,901	$ 10,130	$ 8,456	$ 7,511	$ 9,863
Net Income	$ 8,695	$ 7,842	$ 7,964	$ 7,552	$ 7,875
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 699,342	$ 692,841	$ 674,174	$ 652,332	$ 648,373
Accumulated Depreciation and Amortization	382,925	368,484	351,062	330,187	310,804
Net Property, Plant and Equipment	$ 316,417	$ 324,357	$ 323,112	$ 322,145	$ 337,569
Total Assets	$ 376,703	$ 376,393	$ 380,045	$ 377,716	$ 387,688
Common Shareholder's Equity	$ 50,472	$ 48,671	$ 45,875	$ 42,597	$ 38,195
Long-term Debt (a)	$ 44,828	$ 44,820	$ 44,811	$ 44,802	$ 44,793
Obligations Under Capital Leases (a)	$ 12,227	$ 12,474(b)	$ 269	$ 501	$ 311

(a) Including portion due within one year.
(b) Increased primarily due to a new coal transportation lease. See Note 15.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of the Rockport Plant, we engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and the other co-owner of the Rockport Plant.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M agreed to purchase all of our Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo. In December 2004, the KPSC and the FERC approved a Stipulation and Settlement Agreement which, among other things, extends the unit power agreement with KPCo until December 7, 2022.

The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, we accumulate all expenses monthly and prepare bills for our affiliates. In the month the expenses are incurred, we recognize the billing revenues and establish a receivable from the affiliated companies. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income increased $0.9 million for 2005 compared with 2004. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant calculated and adjusted monthly.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Net Income
(in millions)

Year Ended December 31, 2004		$ 7.8
Change in Gross Margin:		
Wholesale Sales		1.4
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(0.3)	
Depreciation and Amortization	(0.4)	
Taxes Other Than Income Taxes	0.1	
Other Income	0.1	
Total Change in Operating Expenses and Other		(0.5)
Year Ended December 31, 2005		$ 8.7

Gross margin increased $1.4 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The increase in Other Operation and Maintenance expenses resulted from increases in labor costs and an obsolete inventory write-off.

Depreciation and Amortization increased reflecting increased depreciable generating plant for the installation of low NO_x burners at Rockport Plant Unit 2.

Off-Balance Sheet Arrangements

Rockport Plant Unit 2

In 1989, AEGCo and I&M entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. Our future minimum lease payments are $1.3 billion as of December 31, 2005.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote (see Note 15). The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payments due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 35.1	$ -	$ -	$ -	$ 35.1
Interest on Long-term Debt (b)	1.9	-	-	-	1.9
Long-term Debt (c)	45.0	-	-	-	45.0
Capital Lease Obligations (d)	1.0	2.0	1.9	17.0	21.9
Noncancelable Operating Leases (d)	77.5	154.4	154.2	890.9	1,277.0
Total	$ 160.5	$ 156.4	$ 156.1	$ 907.9	$ 1,380.9

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 15.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" beginning on M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING REVENUES	$ 270,755	$ 241,788	$ 233,165
EXPENSES			
Fuel for Electric Generation	140,077	112,470	109,238
Rent – Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	12,099	11,187	10,749
Maintenance	11,518	12,152	10,346
Depreciation and Amortization	23,812	23,390	22,686
Taxes Other Than Income Taxes	4,065	4,176	3,407
TOTAL	259,854	231,658	224,709
OPERATING INCOME	10,901	10,130	8,456
Other Income (Expense):			
Interest Income	24	-	9
Allowance for Equity Funds Used During Construction	98	42	142
Interest Expense	(2,437)	(2,446)	(2,550)
INCOME BEFORE INCOME TAXES	8,586	7,726	6,057
Income Tax Credit	(109)	(116)	(1,907)
NET INCOME	$ 8,695	$ 7,842	$ 7,964

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
BALANCE AT BEGINNING OF PERIOD	$ 24,237	$ 21,441	$ 18,163
Net Income	8,695	7,842	7,964
Cash Dividends Declared	6,894	5,046	4,686
BALANCE AT END OF PERIOD	$ 26,038	$ 24,237	$ 21,441

The common stock of AEGCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	$ 29,671	$ 23,078
Fuel	14,897	16,404
Materials and Supplies	7,017	5,962
Accrued Tax Benefits	2,074	-
Prepayments and Other	9	-
TOTAL	53,668	45,444
PROPERTY, PLANT AND EQUIPMENT		
Electric – Production	684,721	681,254
Other	2,369	3,858
Construction Work in Progress	12,252	7,729
Total	699,342	692,841
Accumulated Depreciation and Amortization	382,925	368,484
TOTAL – NET	316,417	324,357
Noncurrent Assets	6,618	6,592
TOTAL ASSETS	$ 376,703	$ 376,393

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2005 and 2004

		2005		2004
		(in thousands)		
CURRENT LIABILITIES				
Advances from Affiliates	$	35,131	$	26,915
Accounts Payable:				
General		926		443
Affiliated Companies		22,161		17,905
Long-term Debt Due Within One Year		44,828		-
Accrued Taxes		3,055		8,806
Accrued Rent – Rockport Plant Unit 2		4,963		4,963
Other		1,228		1,194
TOTAL		112,292		60,226
NONCURRENT LIABILITIES				
Long-term Debt		-		44,820
Deferred Income Taxes		23,617		24,762
Regulatory Liabilities and Deferred Investment Tax Credits		82,689		84,530
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2		94,333		99,904
Obligations Under Capital Leases		11,930		12,264
Asset Retirement Obligations		1,370		1,216
TOTAL		213,939		267,496
TOTAL LIABILITIES		326,231		327,722
Commitments and Contingencies (Note 7)				
COMMON SHAREHOLDER'S EQUITY				
Common Stock – $1,000 Par Value Per Share				
Authorized and Outstanding – 1,000 Shares		1,000		1,000
Paid-in Capital		23,434		23,434
Retained Earnings		26,038		24,237
TOTAL		50,472		48,671
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$	376,703	$	376,393

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 8,695	$ 7,842	$ 7,964
Adjustments for Noncash Items:			
Depreciation and Amortization	23,812	23,390	22,686
Deferred Income Taxes	(1,666)	(2,219)	(5,838)
Deferred Investment Tax Credits	(3,532)	(3,339)	(3,354)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Other Noncurrent Assets	(457)	3,455	3,486
Changes in Other Noncurrent Liabilities	2,204	(2,511)	1,120
Changes in Components of Working Capital:			
Accounts Receivable	(6,593)	1,670	(6,294)
Fuel, Materials and Supplies	452	3,192	(385)
Accounts Payable	4,739	1,939	476
Accrued Taxes, Net	(7,825)	2,736	3,743
Other Current Assets	(9)	-	-
Other Current Liabilities	34	196	(113)
Net Cash Flows From Operating Activities	14,283	30,780	17,920
INVESTING ACTIVITIES			
Construction Expenditures	(15,372)	(15,757)	(22,197)
Proceeds from Sale of Assets	-	-	105
Net Cash Flows Used For Investing Activities	(15,372)	(15,757)	(22,092)
FINANCING ACTIVITIES			
Change in Advances from Affiliates, Net	8,216	(9,977)	8,858
Principal Payments for Capital Lease Obligations	(233)	-	-
Dividends Paid	(6,894)	(5,046)	(4,686)
Net Cash Flows From (Used For) Financing Activities	1,089	(15,023)	4,172
Net Change in Cash and Cash Equivalents	-	-	-
Cash and Cash Equivalents at Beginning of Period	-	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,170,000, $2,179,000 and $2,283,000 and for income taxes was $13,435,000, $542,000 and $6,483,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $45,000, $12,297,000 and $24,000 in 2005, 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to AEGCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to AEGCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Generating Company:

We have audited the accompanying balance sheets of AEP Generating Company (the "Company") as of December 31, 2005 and 2004, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 793,246	$ 1,212,849	$ 1,797,686	$ 1,739,853	$ 1,753,944
Operating Income	$ 177,281	$ 244,081	$ 452,966	$ 541,132	$ 402,248
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	$ 50,772	$ 294,656	$ 217,547	$ 275,941	$ 182,278
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	(224,551)	(120,534)	-	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	-	122	-	-
Net Income (Loss)	$ (173,779)	$ 174,122	$ 217,669	$ 275,941	$ 182,278
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 2,657,195	$ 2,495,921	$ 2,428,004	$ 2,338,100	$ 2,234,822
Accumulated Depreciation and Amortization	636,078	726,771	697,023	663,266	617,746
Net Property, Plant and Equipment	$ 2,021,117	$ 1,769,150	$ 1,730,981	$ 1,674,834	$ 1,617,076
Total Assets	$ 4,904,912	$ 5,678,320	$ 5,820,360	$ 5,565,599	$ 5,006,294
Common Shareholder's Equity	$ 947,630	$ 1,268,643	$ 1,209,049	$ 1,101,134	$ 1,400,100
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 5,940	$ 5,940	$ 5,940	$ 5,942	$ 5,952
Trust Preferred Securities (b)	$ -	$ -	$ -	$ 136,250	$ 136,250
Long-term Debt (c)	$ 1,853,496	$ 1,907,294	$ 2,291,625	$ 1,438,565	$ 1,253,768
Obligations Under Capital Leases (c)	$ 1,378	$ 880	$ 1,043	$ -	$ -

(a) See "Extraordinary Items" section of Note 2 and "Texas Restructuring" section of Note 6.
(b) See "Trust Preferred Securities" section of Note 16.
(c) Including portion due within one year.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the transmission and distribution of electric power to 729,000 retail customers through REPs in southern and central Texas. We consolidate AEP Texas Central Transition Funding LLC, our wholly-owned subsidiary.

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have already ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Sharing of margins under the CSW Operating Agreement and the SIA will cease at the earlier of FERC approval of our removal from both agreements or May 2006 when our twelve-month rolling peak load ratio will be zero. These trading and marketing margins affect our results of operations and cash flows.

Members of the CSW Operating Agreement are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are generally shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 295
Changes in Gross Margin:		
Texas Supply	(113)	
Texas Wires	22	
Off-system Sales	(2)	
Transmission Revenues	(9)	
Other Revenues	15	
Total Change in Gross Margin		(87)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	38	
Depreciation and Amortization	(19)	
Taxes Other Than Income Taxes	1	
Carrying Costs on Stranded Cost Recovery	(321)	
Other Income	9	
Interest Expense	12	
Total Change in Operating Expenses and Other		(280)
Income Tax Expense		123
Year Ended December 31, 2005		$ 51

Income Before Extraordinary Loss and Cumulative Effect of Accounting Change decreased $244 million in 2005. The key drivers of the decrease were a decrease in Gross Margin of $87 million and a decrease of $321 million related to Carrying Costs on Stranded Cost Recovery, partially offset by a decrease in income tax expense of $123 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of emissions allowances, and purchased power were as follows:

- Texas Supply margins decreased $113 million primarily due to a $458 million decrease in revenue from the expiration in December 2004 of the two year supply contract with our largest REP customer, Centrica; lower capacity sales of $29 million due to the sale of all generation plants except our share of Oklaunion Plant which is held for sale; a $16 million decrease in ERCOT Reliability-Must-Run (RMR) sales; lower optimization margins of $27 million; and decreased nonaffiliated margins of $2 million. These decreases were partially offset by lower fuel and purchased power expenses of $334 million primarily from the loss of our largest REP customer and lower provision for fuel refund of $96 million.
- Texas Wires revenues increased $22 million primarily due to an increase in sales volumes resulting partly from a 6% increase in degree days.
- Transmission Revenues decreased $9 million primarily due to lower ERCOT rates.
- Other Revenues increased $15 million primarily due to increased third party construction project revenues of $30 million resulting from increased activity. This increase was partially offset by lower affiliated transmission revenues of $11 million and lower ancillary services of $2 million.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $38 million primarily due to a $42 million decrease in power plant operations and maintenance expenses due to the sales of virtually all generation plants along with a $31 million decrease in administrative and general expenses primarily related to employee costs and outside services. These decreases were partially offset by increased transmission and distribution related operations and maintenance expenses of $10 million primarily related to station equipment and overhead lines, as well as $28 million of increased third party construction project expenses resulting from increased activity.
- Depreciation and Amortization expense increased $19 million primarily due to the recovery and amortization of securitized transition assets.
- Carrying Costs on Stranded Cost Recovery decreased $321 million. In 2004, TCC booked $302 million of carrying costs income related to 2002 – 2004. Based on the final order in our True-up Proceeding, we determined that adjustments to those carrying costs were required, resulting in carrying costs expense of $19 million in 2005 (see the "Carrying Costs on Net True-up Regulatory Assets" section of Note 6).
- Other Income increased $9 million primarily due to the accrual of interest income resulting from a Texas Appeals Court order (see "Excess Earnings" in the "Texas Restructuring " section of Note 6).
- Interest Expense decreased $12 million primarily due to lower levels of debt outstanding.

Income Taxes

The decrease in Income Tax Expense of $123 million is primarily due to a decrease in pretax book income.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2003		$ 218
Changes in Gross Margin:		
Texas Supply	(27)	
Texas Wires	(213)	
Off-system Sales	(49)	
Transmission Revenues	5	
Other Revenues	1	
Total Change in Gross Margin		(283)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(2)	
Depreciation and Amortization	75	
Taxes Other Than Income Taxes	1	
Carrying Costs on Stranded Cost Recovery	302	
Other Income	4	
Interest Expense	10	
Total Change in Operating Expenses and Other		390
Income Tax Expense		(30)
Year Ended December 31, 2004		$ 295

Income Before Extraordinary Loss and Cumulative Effect of Accounting Change increased $77 million in 2004. The key drivers of the increase were Carrying Costs on Stranded Cost Recovery of $302 million and a decrease in Depreciation and Amortization of $75 million, offset by a decrease in Gross Margin of $283 million.

The major components of our change in Gross Margin, defined as revenues less the related direct costs of fuel, including the consumption of emissions allowances, and purchased power were as follows:

- Texas Supply margins decreased $27 million primarily due to the sale of certain generation plants partially offset by a decrease in the provision for refund due to the final fuel reconciliation true-up.
- Texas Wires revenues decreased $213 million primarily due to establishing regulatory assets in Texas in 2003 (see "Texas Restructuring" and "Wholesale Capacity Auction True-up and Stranded Plant Cost" sections of Note 6).
- Margins from Off-system Sales decreased $49 million primarily due to the sale of certain generation plants.
- Transmission Revenues increased $5 million primarily due to higher ERCOT revenues.

Operating Expenses and Other changed between years as follows:

- Depreciation and Amortization expense decreased $75 million primarily due to the cessation of depreciation on plants sold and plants classified as held for sale.
- Carrying Costs on Stranded Cost Recovery of $302 million were recorded in 2004 for the years 2002 - 2004. There were no carrying costs recorded prior to December 2004 (see the "Carrying Costs on Net True-up Regulatory Assets" section of Note 6).
- Other Income increased $4 million primarily due to increased interest income from a favorable position in the corporate borrowing program.
- Interest Expense decreased $10 million primarily due to the defeasance of $112 million of First Mortgage Bonds, and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, and other financing activities.

Income Taxes

The increase in Income Tax Expense of $30 million is primarily due to an increase in pretax book income and state income taxes, offset in part by the recording of the tax return and tax reserve adjustments.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the years ended December 31, 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 26	$ 837	$ 883
Cash Flows From (Used For):			
Operating Activities	(72,267)	286,608	375,912
Investing Activities	201,083	265,147	(184,049)
Financing Activities	(128,842)	(552,566)	(191,909)
Net Decrease in Cash and Cash Equivalents	(26)	(811)	(46)
Cash and Cash Equivalents at End of Period	$ -	$ 26	$ 837

Operating Activities

Our net cash flows used for operating activities were $72 million in 2005. We incurred a net loss of $174 million during the period and noncash items of $142 million for Depreciation and Amortization, $225 million for an Extraordinary Loss on Stranded Cost Recovery and $(91) million for Deferred Income Taxes. See "Results of Operations" for discussions of these items. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $128 million change in Accrued Taxes. During 2005, we made federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments and we made quarterly estimated federal income tax payments for our 2005 federal income tax liability. The net amount of taxes paid in 2005 was $236 million.

Our net cash flows from operating activities were $287 million in 2004. We produced income of $174 million during the period and noncash items of $123 million for Depreciation and Amortization, $121 million for an Extraordinary Loss on Stranded Cost Recovery (see "Extraordinary Items" section of Note 2 for discussion of this item) and $(302) million for Carrying Costs on Stranded Cost Recovery (see "Carrying Costs on Net True-up Regulatory Assets" section of Note 6). In addition, we paid $62 million to fund our pension plan during 2004. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $117 million change in Accrued Taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payments were made in 2005.

Our net cash flows from operating activities were $376 million in 2003. We produced income of $218 million during the period and noncash items of $198 million for Depreciation and Amortization and $(218) million for Wholesale Capacity Auction True-up (see "Texas Restructuring" and "Wholesale Capacity Auction True-up and Stranded Plant Cost" section of Note 6). The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are a $99 million change in Accounts Receivable primarily due to decreased receivables from risk management activities and a $42 million change in Accrued Taxes as a result of taxes that were accrued during 2003 in excess of the amount remitted to the government.

Investing Activities

Our net cash flows from investing activities in 2005 were $201 million primarily due to $315 million resulting from the proceeds from the sale of a generation plant offset in part by $179 million of construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows from investing activities in 2004 were $265 million primarily due to $430 million resulting from the proceeds from the sale of several of our generation plants, offset in part by $107 million of construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows used for investing activities in 2003 were $184 million primarily due to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Financing Activities

In February 2006, an affiliate issued us a $125 million note. This note is due August 2007 and has a 5.14% interest rate.

Our net cash flows used for financing activities in 2005 were $129 million primarily due to the retirement of long-term debt of $527 million and payment of dividends on common stock of $150 million, offset by the issuance of long-term debt of $467 million, which includes $150 million of affiliated debt.

Our net cash flows used for financing activities in 2004 were $553 million primarily due to the retirement of long-term debt of $380 million and payment of dividends on common stock of $172 million mainly with funds received from the sale of generation plants.

Our net cash flows used for financing activities in 2003 were $192 million primarily due to replacing both short and long-term debt with proceeds from new borrowings and payment of dividends on common stock.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 82.1	$ -	$ -	$ -	$ 82.1
Interest on Fixed Rate Portion of Long-term Debt (b)	86.9	147.6	129.4	598.8	962.7
Fixed Rate Portion of Long-term Debt (c)	152.9	271.4	110.2	998.8	1,533.3
Variable Rate Portion of Long-term Debt (d)	-	-	-	322.9	322.9
Capital Lease Obligations (e)	0.5	0.7	0.3	-	1.5
Noncancelable Operating Leases (e)	5.8	8.5	6.3	3.9	24.5
Energy and Capacity Purchase Contracts (f)	3.9	7.6	6.4	11.2	29.1
Construction Contracts for Assets (g)	101.1	-	-	-	101.1
Total	$ 433.2	$ 435.8	$ 252.6	$ 1,935.6	$ 3,057.2

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.15% and 3.45% at December 31, 2005.
(e) See Note 15.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2005 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 Years	Total
Guarantees of Our Performance (a)	$ -	$ 443	$ -	$ -	$ 443
Transmission Facilities for Third Parties (b)	44	47	-	-	91
Total	$ 44	$ 490	$ -	$ -	$ 534

(a) See "Contracts" section of Note 8.
(b) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

Texas Regulatory Activity

Texas Restructuring

The stranded cost quantification process in Texas continued in 2005 with us filing our True-Up Proceeding in May seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined our stranded costs to be $1.5 billion, including carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. We adjusted our December 2005 books to reflect the final order. Based on the final order, our net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded as a pretax extraordinary loss.

We believe that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT issued in implementing that statute. We intend to seek rehearing of the PUCT's rulings. If the PUCT does not make significant changes in response to our request for reconsideration, we expect to challenge certain of the PUCT's rulings through appeals to Texas state and federal courts. Although we believe we have meritorious arguments, we cannot predict the ultimate outcome of any requested rehearings or appeals.

We anticipate filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include other true-up items, which we anticipate will be negative, and as such will reduce rates to customers through a negative competition transition charge (CTC). The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. We will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an accumulated deferred federal income tax benefit (ADFIT) related to our stranded generation cost, and the positive wholesale capacity auction true-up balance. We anticipate making a filing to implement the CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	$ 1,275
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	$ 1,804

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

If we determine in future securitization and competition transition charge proceedings that it is probable we cannot recover a portion of our recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. See "Texas

Restructuring" section of Note 6 for a discussion of the $200 million difference between the final order and our recorded balance.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet As of December 31, 2005 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 14,147	$ 164	$ 14,311
Noncurrent Assets	11,609	-	11,609
Total MTM Derivative Contract Assets	25,756	164	25,920
Current Liabilities	(12,531)	(493)	(13,024)
Noncurrent Liabilities	(7,799)	(58)	(7,857)
Total MTM Derivative Contract Liabilities	(20,330)	(551)	(20,881)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5,426	$ (387)	$ 5,039

MTM Risk Management Contract Net Assets Year Ended December 31, 2005 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 9,701
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,835)
Fair Value of New Contracts at Inception When Entered During the Period (a)	171
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	389
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	-
Total MTM Risk Management Contract Net Assets	5,426
Net Cash Flow Hedge Contracts	(387)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 5,039

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,042	$ 583	$ 169	$ -	$ -	$ -	$ 1,794
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,460	1,308	1,565	774	-	-	6,107
Prices Based on Models and Other Valuation Methods (b)	(1,887)	(1,070)	(598)	124	603	353	(2,475)
Total	$ 1,615	$ 821	$ 1,136	$ 898	$ 603	$ 353	$ 5,426

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2004	$ 657
Changes in Fair Value	(635)
Reclassifications from AOCI to Net Loss for Cash Flow Hedges Settled	(246)
Ending Balance in AOCI December 31, 2005	$ (224)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $186 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$111	$184	$88	$32	$157	$511	$220	$75

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $93 million and $120 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

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AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 729,815	$ 1,148,930	$ 1,624,872
Sales to AEP Affiliates	14,973	47,039	153,770
Other – Nonaffiliated	48,458	16,880	19,044
TOTAL	793,246	1,212,849	1,797,686
EXPENSES			
Fuel and Other Consumables for Electric Generation	13,363	60,725	89,389
Fuel from Affiliates for Electric Generation	84	101,906	195,527
Purchased Electricity for Resale	28,947	206,304	373,388
Purchased Electricity from AEP Affiliates	-	6,140	19,097
Other Operation	291,160	316,508	306,073
Maintenance	50,888	63,599	71,361
Depreciation and Amortization	141,806	122,585	197,776
Taxes Other Than Income Taxes	89,717	91,001	92,109
TOTAL	615,965	968,768	1,344,720
OPERATING INCOME	177,281	244,081	452,966
Other Income (Expense):			
Interest Income	16,228	6,604	3,058
Carrying Costs Income (Expense)	(19,293)	301,644	-
Allowance for Equity Funds Used During Construction	1,003	1,170	507
Interest Expense	(112,006)	(123,785)	(133,812)
INCOME BEFORE INCOME TAXES	63,213	429,714	322,719
Income Tax Expense	12,441	135,058	105,172
INCOME BEFORE EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	50,772	294,656	217,547
EXTRAORDINARY LOSS ON STRANDED COST RECOVERY, Net of Tax	(224,551)	(120,534)	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, Net of Tax	-	-	122
NET INCOME (LOSS)	(173,779)	174,122	217,669
Preferred Stock Dividend Requirements	241	241	241
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (174,020)	$ 173,881	$ 217,428

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 55,292	$ 132,606	$ 986,396	$ (73,160)	$ 1,101,134
Common Stock Dividends			(120,801)		(120,801)
Preferred Stock Dividends			(241)		(241)
TOTAL					980,092
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $965				(1,792)	(1,792)
Minimum Pension Liability, Net of Tax of $7,043				13,080	13,080
NET INCOME			217,669		217,669
TOTAL COMPREHENSIVE INCOME					228,957
DECEMBER 31, 2003	55,292	132,606	1,083,023	(61,872)	1,209,049
Common Stock Dividends			(172,000)		(172,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,036,808
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,338				2,485	2,485
Minimum Pension Liability, Net of Tax of $31,790				55,228	55,228
NET INCOME			174,122		174,122
TOTAL COMPREHENSIVE INCOME					231,835
DECEMBER 31, 2004	55,292	132,606	1,084,904	(4,159)	1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,118,402
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $474				(881)	(881)
Minimum Pension Liability, Net of Tax of $42				3,888	3,888
NET LOSS			(173,779)		(173,779)
TOTAL COMPREHENSIVE LOSS					(170,772)
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ 26
Other Cash Deposits	66,153	135,106
Accounts Receivable:		
Customers	209,957	140,090
Affiliated Companies	23,486	67,860
Accrued Unbilled Revenues	25,606	25,906
Allowance for Uncollectible Accounts	(143)	(3,493)
Total Accounts Receivable	258,906	230,363
Unbilled Construction Costs	19,440	5,213
Materials and Supplies	13,897	12,288
Risk Management Assets	14,311	14,048
Prepayments and Other	5,231	6,822
TOTAL	377,938	403,866
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	817,351	788,371
Distribution	1,476,683	1,433,380
Other	233,361	223,558
Construction Work in Progress	129,800	50,612
Total	2,657,195	2,495,921
Accumulated Depreciation and Amortization	636,078	726,771
TOTAL - NET	2,021,117	1,769,150
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,688,787	2,061,978
Securitized Transition Assets	593,401	642,384
Long-term Risk Management Assets	11,609	9,508
Employee Benefits and Pension Assets	114,733	109,641
Deferred Charges and Other	53,011	53,644
TOTAL	2,461,541	2,877,155
Assets Held for Sale – Texas Generation Plants	44,316	628,149
TOTAL ASSETS	$ 4,904,912	$ 5,678,320

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 82,080	$ 207
Accounts Payable:		
General	82,666	92,218
Affiliated Companies	65,574	64,045
Long-term Debt Due Within One Year – Nonaffiliated	152,900	365,742
Risk Management Liabilities	13,024	8,394
Accrued Taxes	54,566	184,014
Accrued Interest	32,497	41,227
Other	45,927	26,674
TOTAL	529,234	782,521
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,550,596	1,541,552
Long-term Debt – Affiliated	150,000	-
Long-term Risk Management Liabilities	7,857	4,896
Deferred Income Taxes	1,048,372	1,247,111
Regulatory Liabilities and Deferred Investment Tax Credits	652,143	559,930
Deferred Credits and Other	13,140	17,744
TOTAL	3,422,108	3,371,233
Liabilities Held for Sale – Texas Generation Plants	-	249,983
TOTAL LIABILITIES	3,951,342	4,403,737
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $25 Par Value Per Share:		
Authorized – 12,000,000 Shares		
Outstanding – 2,211,678 Shares	55,292	55,292
Paid-in Capital	132,606	132,606
Retained Earnings	760,884	1,084,904
Accumulated Other Comprehensive Income (Loss)	(1,152)	(4,159)
TOTAL	947,630	1,268,643
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,904,912	$ 5,678,320

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income (Loss)	$ (173,779)	$ 174,122	$ 217,669
Adjustments for Noncash Items:			
Depreciation and Amortization	141,806	122,585	197,776
Accretion of Asset Retirement Obligations	7,549	16,726	15,538
Deferred Income Taxes	(91,387)	16,490	19,393
Cumulative Effect of Accounting Change, Net of Tax	-	-	(122)
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	224,551	120,534	-
Carrying Costs on Stranded Cost Recovery	19,293	(301,644)	-
Amortization of Deferred Property Taxes	-	3,637	-
Mark-to-Market of Risk Management Contracts	4,275	2,241	(6,341)
Wholesale Capacity Auction True-up	769	(79,973)	(218,000)
Pension Contributions to Qualified Plan Trusts	(3,953)	(61,910)	(86)
Over/Under Fuel Recovery	(34,328)	61,500	81,000
Change in Other Noncurrent Assets	(8,192)	96,434	37,130
Change in Other Noncurrent Liabilities	(3,940)	(20,199)	(69,984)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(28,947)	2,352	99,136
Fuel, Materials and Supplies	(1,559)	(10,641)	15,851
Accounts Payable	6,797	26,008	(28,692)
Accrued Taxes, Net	(128,022)	116,996	42,227
Other Current Assets	(14,313)	1,817	(6,380)
Other Current Liabilities	11,113	(467)	(20,203)
Net Cash Flows From (Used for) Operating Activities	(72,267)	286,608	375,912
INVESTING ACTIVITIES			
Construction Expenditures	(178,628)	(106,656)	(130,900)
Change in Other Cash Deposits, Net	68,953	(70,062)	19,491
Change in Advances to Affiliates, Net	-	60,699	(60,699)
Purchases of Investment Securities	(154,364)	(99,667)	(51,000)
Sales of Investment Securities	149,804	87,471	40,628
Proceeds from Sale of Assets	315,318	429,553	7,455
Other	-	(36,191)	(9,024)
Net Cash Flows From (Used For) Investing Activities	201,083	265,147	(184,049)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	316,901	-	953,136
Issuance of Long-term Debt – Affiliated	150,000	-	-
Change in Short-term Debt, Net – Affiliated	-	-	(650,000)
Change in Advances from Affiliates, Net	81,873	207	(126,711)
Retirement of Long-term Debt	(526,897)	(380,096)	(247,127)
Retirement of Preferred Stock	-	-	(2)
Principal Payments for Capital Lease Obligations	(478)	(436)	(163)
Dividends Paid on Common Stock	(150,000)	(172,000)	(120,801)
Dividends Paid on Cumulative Preferred Stock	(241)	(241)	(241)
Net Cash Used For Financing Activities	(128,842)	(552,566)	(191,909)
Net Decrease in Cash and Cash Equivalents	(26)	(811)	(46)
Cash and Cash Equivalents at Beginning of Period	26	837	883
Cash and Cash Equivalents at End of Period	$ -	$ 26	$ 837

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $104,701,000, $117,325,000 and $129,491,000 and for income taxes was $235,697,000, $(1,058,000) and $49,630,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $977,000, $348,000 and $1,223,000 in 2005, 2004 and 2003, respectively. Noncash Construction Expenditures included in Accounts Payable of $11,037,000, $1,838,000, and $1,727,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TCC's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TCC. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Texas Central Company:

We have audited the accompanying consolidated balance sheets of AEP Texas Central Company and subsidiary (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiary as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003. As discussed in Note 16 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

AEP TEXAS NORTH COMPANY

AEP TEXAS NORTH COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 458,888	$ 553,458	$ 533,511	$ 503,408	$ 563,535
Operating Income (Loss)	$ 76,699	$ 91,071	$ 107,405	$ (6,250)	$ 36,034
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 41,476	$ 47,659	$ 55,663	$ (13,677)	$ 12,310
Extraordinary Loss, Net of Tax	-	-	(177)	-	-
Cumulative Effect of Accounting Changes, Net of Tax	(8,472)	-	3,071	-	-
Net Income (Loss)	$ 33,004	$ 47,659	$ 58,557	$ (13,677)	$ 12,310
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,285,114	$ 1,305,571	$ 1,281,620	$ 1,249,996	$ 1,262,036
Accumulated Depreciation and Amortization	478,519	527,770	507,420	493,981	475,346
Net Property, Plant and Equipment	$ 806,595	$ 777,801	$ 774,200	$ 756,015	$ 786,690
Total Assets	$ 1,043,834	$ 1,043,162	$ 978,801	$ 965,916	$ 941,443
Common Shareholder's Equity	$ 313,919	$ 310,421	$ 238,275	$ 180,744	$ 245,535
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 2,357	$ 2,357	$ 2,357	$ 2,367	$ 2,367
Long-term Debt (a)	$ 276,845	$ 314,357	$ 356,754	$ 132,500	$ 255,967
Obligations Under Capital Leases (a)	$ 724	$ 534	$ 473	$ -	$ -

(a) Including portion due within one year.

MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the transmission and distribution of electric power to 189,000 retail customers through REPs in western and central Texas. Although we are engaged in the generation and purchase of electric power for sale to the market and to meet wholesale contracts, the deregulation of electric power in the state of Texas requires this activity to be separated from our transmission and distribution activities. We also sell electric power at wholesale to other utilities, municipalities, rural electric cooperatives and REPs in Texas.

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have already ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, once approved by the FERC, our sharing of margins under the CSW Operating Agreement and the SIA will cease, which affects our results of operations and cash flows.

Members of the CSW Operating Agreement are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are generally shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Extraordinary Loss and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 48
Changes in Gross Margin:		
Texas Supply	(7)	
Texas Wires	4	
Off-system Sales	(2)	
Other Revenues	(23)	
Total Change in Gross Margin		(28)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	16	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(1)	
Other Income	2	
Interest Expense	2	
Total Change in Operating Expenses and Other		17
Income Tax Expense		4
Year Ended December 31, 2005		$ 41

Income Before Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $7 million primarily due to a decrease in Gross Margin partially offset by a reduction in operating expenses.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of emissions allowances and purchased power were as follows:

- Texas Supply margins decreased by $7 million primarily due to the expiration in December 2004 of the two year supply contract with our largest REP customer, Centrica; offset by an increase in nonaffiliated margin, capacity sales and a decrease in provision for rate refund primarily due to fuel reconciliation issues in 2004.
- Texas Wires revenue increased by $4 million primarily due to an increase in billed sales volumes resulting from an 11% increase in degree days.
- Margins from Off-system Sales decreased by $2 million primarily due to unfavorable optimization activities.
- Other Revenues decreased $23 million primarily due to a decrease of $12 million in third party construction projects, reduced affiliated transmission revenue of $7 million and lower ERCOT ancillary services of $2 million.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $16 million. The decrease was primarily due to lower expenses related to third party construction projects of $13 million and a favorable settlement related to the Ft. Davis wind farm, which was impaired in 2002. Further reductions include $7 million of regulatory expenses, outside services, and administrative and general expenses, primarily related to lower employee-related costs. Power plant and transmission maintenance increased $3 million primarily due to higher joint facility charges and substation and overhead line maintenance.
- Interest Expense decreased $2 million primarily due to long-term debt maturities in 2004 and interest related to the 2004 FERC settlement with wholesale customers.

Income Taxes

The decrease in Income Tax Expense of $4 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payments due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Interest on Long-term Debt (a)	$ 15.7	$ 30.4	$ 30.1	$ 56.2	$ 132.4
Long-term Debt (b)	-	8.2	-	269.3	277.5
Capital Lease Obligations (c)	0.2	0.3	0.3	-	0.8
Noncancelable Operating Leases (c)	2.4	3.9	3.5	2.4	12.2
Energy and Capacity Purchase Contracts (d)	8.1	15.6	13.2	23.3	60.2
Construction Contracts for Capital Assets (e)	23.1	-	-	-	23.1
Total	$ 49.5	$ 58.4	$ 47.1	$ 351.2	$ 506.2

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(b) See Note 16. Represents principal only excluding interest.
(c) See Note 15.
(d) Represents contractual cash flows of energy and capacity purchase contracts.
(e) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Balance Sheet
As of December 31, 2005
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 7,033	$ 81	$ 7,114
Noncurrent Assets	5,772	-	5,772
Total MTM Derivative Contract Assets	12,805	81	12,886
Current Liabilities	(6,230)	(245)	(6,475)
Noncurrent Liabilities	(3,877)	(29)	(3,906)
Total MTM Derivative Contract Liabilities	(10,107)	(274)	(10,381)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,698	$ (193)	$ 2,505

MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 4,192
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(2,088)
Fair Value of New Contracts at Inception When Entered During the Period (a)	80
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(1)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	515
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	-
Total MTM Risk Management Contract Net Assets	2,698
Net Cash Flow Hedge Contracts	(193)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 2,505

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 518	$ 290	$ 84	$ -	$ -	$ -	$ 892
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,223	650	778	385	-	-	3,036
Prices Based on Models and Other Valuation Methods (b)	(938)	(532)	(297)	62	300	175	(1,230)
Total	$ 803	$ 408	$ 565	$ 447	$ 300	$ 175	$ 2,698

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2004	$ 285
Changes in Fair Value	(290)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(106)
Ending Balance in AOCI December 31, 2005	$ (111)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $93 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$55	$92	$44	$16	$68	$221	$95	$33

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $13 million and $13 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 369,954	$ 447,908	$ 420,718
Sales to AEP Affiliates	47,164	51,680	55,386
Other	41,770	53,870	57,407
TOTAL	458,888	553,458	533,511
EXPENSES			
Fuel and Other Consumables for Electric Generation	46,953	54,447	39,082
Fuel from Affiliates for Electric Generation	629	46,496	44,197
Purchased Electricity for Resale	125,567	133,770	87,006
Purchased Electricity from AEP Affiliates	23	5,211	39,409
Other Operation	120,618	140,206	140,639
Maintenance	23,636	20,602	18,961
Depreciation and Amortization	41,466	39,025	36,242
Taxes Other Than Income Taxes	23,297	22,630	20,570
TOTAL	382,189	462,387	426,106
OPERATING INCOME	76,699	91,071	107,405
Other Income (Expense):			
Interest Income	2,447	665	174
Allowance for Equity Funds Used During Construction	724	417	396
Interest Expense	(19,817)	(21,985)	(22,049)
INCOME BEFORE INCOME TAXES	60,053	70,168	85,926
Income Tax Expense	18,577	22,509	30,263
INCOME BEFORE EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	41,476	47,659	55,663
EXTRAORDINARY LOSS, Net of Tax	-	-	(177)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax	(8,472)	-	3,071
NET INCOME	33,004	47,659	58,557
Preferred Stock Dividend Requirements, Net of Gain on Reacquired Preferred Stock	104	103	101
EARNINGS APPLICABLE TO COMMON STOCK	$ 32,900	$ 47,556	$ 58,456

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 137,214	$ 2,351	$ 71,942	$ (30,763)	$ 180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(104)		(104)
Gain on Reacquired Preferred Stock			3		3
TOTAL					175,673
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $316				(586)	(586)
Minimum Pension Liability, Net of Tax of $2,498				4,631	4,631
NET INCOME			58,557		58,557
TOTAL COMPREHENSIVE INCOME					62,602
DECEMBER 31, 2003	137,214	2,351	125,428	(26,718)	238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					236,172
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $477				886	886
Minimum Pension Liability, Net of Tax of $13,841				25,704	25,704
NET INCOME			47,659		47,659
TOTAL COMPREHENSIVE INCOME					74,249
DECEMBER 31, 2004	137,214	2,351	170,984	(128)	310,421
Common Stock Dividends			(29,026)		(29,026)
Preferred Stock Dividends			(104)		(104)
TOTAL					281,291
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $213				(396)	(396)
Minimum Pension Liability, Net of Tax of $11				20	20
NET INCOME			33,004		33,004
TOTAL COMPREHENSIVE INCOME					32,628
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Advances to Affiliates	34,286	51,504
Accounts Receivable:		
Customers	77,678	81,836
Affiliated Companies	26,149	21,474
Accrued Unbilled Revenues	5,016	3,789
Allowance for Uncollectible Accounts	(18)	(787)
Total Accounts Receivable	108,825	106,312
Unbilled Construction Costs	1,321	22,065
Fuel	2,636	3,148
Materials and Supplies	6,858	8,273
Risk Management Assets	7,114	6,071
Prepayments and Other	3,883	4,660
TOTAL	164,923	202,033
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	288,934	287,212
Transmission	289,029	281,359
Distribution	492,878	474,961
Other	167,849	238,418
Construction Work in Progress	46,424	23,621
Total	1,285,114	1,305,571
Accumulated Depreciation and Amortization	478,519	527,770
TOTAL - NET	806,595	777,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	9,787	12,023
Long-term Risk Management Assets	5,772	4,110
Employee Benefits and Pension Assets	46,289	44,912
Deferred Charges and Other	10,468	2,283
TOTAL	72,316	63,328
TOTAL ASSETS	$ 1,043,834	$ 1,043,162

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 19,739	$ 14,077
Affiliated Companies	84,923	52,801
Long-term Debt Due Within One Year – Nonaffiliated	-	37,609
Risk Management Liabilities	6,475	3,628
Accrued Taxes	21,212	37,269
Other	21,050	15,912
TOTAL	153,399	161,296
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	276,845	276,748
Long-term Risk Management Liabilities	3,906	2,116
Deferred Income Taxes	132,335	138,465
Regulatory Liabilities and Deferred Investment Tax Credits	139,732	140,774
Deferred Credits and Other	21,341	10,985
TOTAL	574,159	569,088
TOTAL LIABILITIES	727,558	730,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $25 Par Value Per Share:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	137,214	137,214
Paid-in Capital	2,351	2,351
Retained Earnings	174,858	170,984
Accumulated Other Comprehensive Income (Loss)	(504)	(128)
TOTAL	313,919	310,421
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 1,043,834	$ 1,043,162

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 33,004	$ 47,659	$ 58,557
Adjustments for Noncash Items:			
Depreciation and Amortization	41,466	39,025	36,242
Deferred Income Taxes	(4,578)	4,236	(3,493)
Cumulative Effect of Accounting Changes, Net of Tax	8,472	-	(3,071)
Extraordinary Loss, Net of Tax	-	-	177
Mark-to-Market of Risk Management Contracts	1,494	428	(2,558)
Pension Contributions to Qualified Plan Trusts	(1,409)	(21,172)	(410)
Over/Under Fuel Recovery	996	10,100	15,960
Change in Other Noncurrent Assets	(3,003)	(9,264)	6,987
Change in Other Noncurrent Liabilities	(1,897)	12,444	(6,506)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(2,513)	(20,620)	38,367
Fuel, Materials and Supplies	1,927	8,374	2,462
Accounts Payable	35,659	8,238	(64,760)
Accrued Taxes, Net	(16,057)	14,392	19,180
Unbilled Construction Costs	20,744	(5,122)	(14,287)
Other Current Assets	(99)	764	(2,052)
Other Current Liabilities	5,138	90	(4,485)
Net Cash Flows From Operating Activities	119,344	89,572	76,310
INVESTING ACTIVITIES			
Construction Expenditures	(63,014)	(35,901)	(45,641)
Change in Other Cash Deposits, Net	876	555	(1,706)
Change In Advances to Affiliates, Net	17,218	(9,911)	(41,593)
Proceeds from Sale of Assets	1,033	510	688
Other	(8,469)	-	-
Net Cash Flows Used for Investing Activities	(52,356)	(44,747)	(88,252)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	-	-	222,455
Change in Short-term Debt, Net – Affiliated	-	-	(125,000)
Change in Advances From Affiliates, Net	-	-	(80,407)
Retirement of Long-term Debt - Nonaffiliated	(37,609)	(42,506)	-
Retirement of Preferred Stock	-	-	(10)
Principal Payments for Capital Lease Obligations	(249)	(216)	(84)
Dividends Paid on Common Stock	(29,026)	(2,000)	(4,970)
Dividends Paid on Cumulative Preferred Stock	(104)	(103)	(104)
Net Cash Flows From (Used For) Financing Activities	(66,988)	(44,825)	11,880
Net Decrease in Cash and Cash Equivalents	-	-	(62)
Cash and Cash Equivalents at Beginning of Period	-	-	62
Cash and Cash Equivalents at End of Period	$ -	$ -	$ -

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $19,042,000, $20,860,000 and $16,384,000 and for income taxes was $41,306,000, $6,905,000 and $16,081,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $442,000, $282,000 and $560,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $3,159,000, $1,034,000 and $977,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TNC's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TNC. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas North Company:

We have audited the accompanying balance sheets of AEP Texas North Company (the "Company") as of December 31, 2005 and 2004, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Texas North Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, and FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 11 to the financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 2,176,273	$ 1,957,846	$ 1,950,867	$ 1,848,258	$ 1,845,740
Operating Income	$ 283,388	$ 328,561	$ 416,410	$ 430,189	$ 376,114
Income Before Cumulative Effect of Accounting Changes	$ 135,832	$ 153,115	$ 202,783	$ 205,492	$ 161,818
Cumulative Effect of Accounting Changes, Net of Tax	(2,256)	-	77,257	-	-
Net Income	$ 133,576	$ 153,115	$ 280,040	$ 205,492	$ 161,818
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 7,176,961	$ 6,563,207	$ 6,174,158	$ 5,929,348	$ 5,698,230
Accumulated Depreciation and Amortization	2,524,855	2,456,417	2,334,013	2,343,507	2,219,014
Net Property, Plant and Equipment	$ 4,652,106	$ 4,106,790	$ 3,840,145	$ 3,585,841	$ 3,479,216
Total Assets	$ 6,254,093	$ 5,239,918	$ 4,977,011	$ 4,722,442	$ 4,572,194
Long-term Debt (a)	$ 2,151,378	$ 1,784,598	$ 1,864,081	$ 1,893,861	$ 1,556,559
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 17,784	$ 17,784	$ 17,784	$ 17,790	$ 17,790
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	$ -	$ -	$ 5,360	$ 10,860	$ 10,860
Common Shareholder's Equity	$ 1,803,701	$ 1,409,718	$ 1,336,987	$ 1,166,057	$ 1,126,701
Obligations Under Capital Leases (a)	$ 14,892	$ 19,878	$ 25,352	$ 33,589	$ 46,285

(a) Including portion due within one year.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 942,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. We consolidate Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and our acquisition of the Ceredo Generating Station, we, as a member with a generating capacity deficit, expect to incur reduced capacity charges in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

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

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 153
Changes in Gross Margin:		
Retail Margins	(55)	
Off-system Sales	60	
Transmission Revenues	(15)	
Other Revenues	2	
Total Change in Gross Margin		(8)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(40)	
Depreciation and Amortization	3	
Carrying Costs Income	14	
Interest Expense	(7)	
Other Income	2	
Total Change in Operating Expenses and Other		(28)
Income Tax Expense		19
Year Ended December 31, 2005		$ 136

Income Before Cumulative Effect of Accounting Changes decreased by $17 million to $136 million in 2005. The key drivers of the decrease were a $28 million net increase in operating expenses and other and an $8 million net decrease in gross margin offset by a $19 million decrease in Income Tax Expense.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins decreased by $55 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand that was established in December 2004 resulting in a $57 million increase in capacity settlement payments under the Interconnection Agreement. In addition, there was a $27 million decrease in fuel margins resulting from higher fuel costs. The decrease in retail margins was partially offset by an increase of $26 million in retail sales due to favorable weather conditions.
- Margins from Off-system Sales for 2005 increased by $60 million compared to 2004 primarily due to increased AEP Power Pool physical sales as well as favorable optimization activity.
- Transmission Revenues decreased $15 million primarily due to the elimination of revenues related to through and out rates partially offset by an increase in revenues due to replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $40 million primarily due to a $15 million increase in generation operation and maintenance expenses, a $10 million increase in system dispatch costs related to our operation in PJM and a $9 million increase in costs associated with the AEP Transmission Equalization Agreement.
- Carrying Costs Income increased $14 million primarily related to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased $7 million primarily due to long-term debt issuances in 2005.

Income Taxes

The decrease in Income Tax Expense of $19 million is primarily due to a decrease in pretax book income and a reduction of 2005 state income taxes due in part as a result of the phase-out of the Ohio Franchise Tax.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ 203
Changes in Gross Margin:		
Retail Margins	5	
Off-system Sales	1	
Transmission Revenues	(9)	
Other Revenues	5	
Total Change in Gross Margin		2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(69)	
Depreciation and Amortization	(18)	
Taxes Other Than Income Taxes	(3)	
Interest Expense	16	
Other Income	2	
Total Change in Operating Expenses and Other		(72)
Income Tax Expense		20
Year Ended December 31, 2004		$ 153

Income Before Cumulative Effect of Accounting Changes decreased by $50 million to $153 million in 2004. The key drivers of the decrease were a $72 million net increase in Operating Expenses and Other partially offset by a $20 million decrease in Income Tax Expense.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased by $5 million in comparison to 2003 primarily due to increases in retail sales and purchasing less power from the AEP Power Pool. Cooling degree days were 28% higher than 2003. The increase in retail sales were offset by a decrease in fuel margins resulting from higher fuel costs.
- Transmission Revenues decreased $9 million primarily due to the elimination of $8 million of revenues related to through and out rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.
- Other Revenues increased $5 million primarily due to increased gains recorded on the disposition of emission allowances in 2004.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $69 million primarily due to $40 million in boiler plant maintenance in 2004. In addition, there were increased administrative and support expenses, increased insurance premiums and increased removal costs in 2004. These increases were offset by reduced labor costs.
- Depreciation and Amortization increased $18 million due to a greater depreciable base in 2004 including the addition of capitalized software costs partially offset by reduced amortization of Virginia's transition generation regulatory assets.
- Interest Expense decreased $16 million due to reduced interest rates from refinancing higher cost debt and increased construction-related capitalized interest.

Income Taxes

The decrease in Income Tax Expense of $20 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,543	$ 4,714	$ 4,285
Cash Flows From (Used For):			
Operating Activities	151,474	406,324	449,848
Investing Activities	(687,515)	(391,904)	(307,243)
Financing Activities	536,239	(17,591)	(142,176)
Net Increase (Decrease) in Cash and Cash Equivalents	198	(3,171)	429
Cash and Cash Equivalents at End of Period	$ 1,741	$ 1,543	$ 4,714

Operating Activities

Our Net Cash Flows From Operating Activities were $151 million in 2005. We produced income of $134 million during the period and noncash expense items of $190 million for Depreciation and Amortization and $73 million for Deferred Income Taxes offset by an increase in Pension Contributions to Qualified Plan Trusts of $129 million. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item, a decrease in Accrued Taxes, Net of $74 million. During 2005, we made federal income tax payments of $75 million.

Our Net Cash Flows From Operating Activities were $406 million in 2004. We produced income of $153 million during the period and noncash expense items of $194 million for Depreciation and Amortization and $48 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item, an increase in Accrued Taxes, Net of $40 million. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. A payment was made in March 2005 when the 2004 federal income tax return extension was filed.

Our Net Cash Flows From Operating Activities were $450 million in 2003. We produced income of $280 million during the period and had a noncash expense item of $176 million for Depreciation and Amortization as a result of increased amortization for the net generation-related regulatory assets related to our West Virginia territory. This increase in amortization is related to our distribution business and is being recovered through rates. Other noncash expense items include $77 million for the Cumulative Effect of Accounting Changes due to the implementation of SFAS 143 & EITF 02-3 and $56 million of Mark-to-Market of Risk Management Contracts as a result of increased gains from risk management activities. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items in 2003.

Investing Activities

Our Net Cash Flows Used For Investing Activities during 2005, 2004, and 2003 primarily reflect our construction expenditures of $598 million, $437 million, and $268 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2005 and 2004, capital projects for transmission expenditures are primarily related to the Wyoming-Jacksons Ferry 765 KV line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on our plants and the flue gas desulfurization (FGD) project at the Mountaineer Plant. In 2005, we also acquired the Ceredo Generating Station for approximately $100 million.

Financing Activities

Our Net Cash Flows From Financing Activities were $536 million in 2005. We issued Senior Unsecured Notes of $850 million and Notes Payable - Affiliated of $100 million. We also received Capital Contributions from Parent of $200 million. We retired $450 million of Senior Unsecured Notes and three First Mortgage Bonds totaling $125 million. We reduced short-term borrowing from the Utility Money Pool by $17 million.

Our Net Cash Flows Used For Financing Activities were $18 million in 2004. We issued Senior Unsecured Notes of $125 million and reacquired First Mortgage Bonds, Senior Unsecured Notes, and Installment Purchase Contracts of $116 million, $50 million, and $40 million, respectively, at higher stated interest rates. We also increased borrowings from the Utility Money Pool of $128 million and paid common dividends of $50 million.

Our Net Cash Flows Used For Financing Activities were $142 million in 2003. We issued two series of Senior Unsecured Notes, each in the amount of $200 million that were used to call First Mortgage Bonds, Senior Unsecured Notes and fund maturities. Additionally, we incurred obligations of $188 million in Installment Purchase Contracts to redeem higher cost Installment Purchase Contracts. In addition, we had increased borrowings from the Utility Money Pool of $44 million and paid common dividends of $128 million.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 194.1	$ -	$ -	$ -	$ 194.1
Interest on Fixed Rate Portion of Long-term Debt (b)	99.3	176.7	137.8	862.5	1,276.3
Fixed Rate Portion of Long-term Debt (c)	147.0	399.2	400.0	1,051.9	1,998.1
Variable Rate Portion of Long-term Debt (d)	-	125.0	-	40.0	165.0
Capital Lease Obligations (e)	6.7	7.6	2.5	0.3	17.1
Noncancelable Operating Leases (e)	9.8	14.1	10.1	11.5	45.5
Fuel Purchase Contracts (f)	583.6	736.2	433.3	536.9	2,290.0
Energy and Capacity Purchase Contracts (g)	0.6	0.4	-	-	1.0
Construction Contracts for Capital Assets (h)	197.7	250.0	-	-	447.7
Total	$ 1,238.8	$ 1,709.2	$ 983.7	$ 2,503.1	$ 6,434.8

(a) *Represents* short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.10% and 4.85% at December 31, 2005.
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet As of December 31, 2005 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 131,135	$ 1,112	$ -	$ 132,247
Noncurrent Assets	176,231	-	-	176,231
Total MTM Derivative Contract Assets	307,366	1,112	-	308,478
Current Liabilities	(116,644)	(3,771)	(750)	(121,165)
Noncurrent Liabilities	(134,315)	(1,234)	(11,568)	(147,117)
Total MTM Derivative Contract Liabilities	(250,959)	(5,005)	(12,318)	(268,282)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 56,407	$ (3,893)	$ (12,318)	$ 40,196

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets Year Ended December 31, 2005 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 54,124
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(13,085)
Fair Value of New Contracts at Inception When Entered During the Period (a)	1,053
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(1,518)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	13,300
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2,533
Total MTM Risk Management Contract Net Assets	56,407
Net Cash Flow & Fair Value Hedge Contracts	(3,893)
DETM Assignment (d)	(12,318)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 40,196

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 6,884	$ 3,854	$ 1,115	$ -	$ -	$ -	$ 11,853
Prices Provided by Other External Sources – OTC Broker Quotes (a)	17,630	13,388	12,251	6,137	-	-	49,406
Prices Based on Models and Other Valuation Methods (b)	(10,023)	(4,117)	(2,248)	3,272	7,818	446	(4,852)
Total	$ 14,491	$ 13,125	$ 11,118	$ 9,409	$ 7,818	$ 446	$ 56,407

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate forward and swap transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)
Changes in Fair Value	330	-	(4,845)	(4,515)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(4,232)	5	1,645	(2,582)
Ending Balance in AOCI December 31, 2005	$ (1,480)	$ (171)	$ (14,770)	$ (16,421)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,414 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$732	$1,216	$579	$209	$577	$1,883	$812	$277

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $142 million and $99 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,845,170	$ 1,698,220	$ 1,671,976
Sales to AEP Affiliates	322,333	252,128	267,345
Other	8,770	7,498	11,546
TOTAL	2,176,273	1,957,846	1,950,867
EXPENSES			
Fuel and Other Consumables for Electric Generation	549,773	432,420	465,221
Purchased Electricity for Resale	110,693	84,433	66,084
Purchased Electricity from AEP Affiliates	453,600	370,953	351,210
Other Operation	316,517	279,906	250,333
Maintenance	179,119	175,283	135,596
Depreciation and Amortization	190,216	193,525	175,772
Taxes Other Than Income Taxes	92,967	92,765	90,241
TOTAL	1,892,885	1,629,285	1,534,457
OPERATING INCOME	283,388	328,561	416,410
Other Income (Expense):			
Interest Income	2,540	1,985	3,395
Carrying Costs Income	14,438	255	199
Allowance for Equity Funds Used During Construction	7,956	6,560	3,201
Interest Expense	(106,301)	(99,135)	(115,202)
INCOME BEFORE INCOME TAXES	202,021	238,226	308,003
Income Tax Expense	66,189	85,111	105,220
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	135,832	153,115	202,783
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax	(2,256)	-	77,257
NET INCOME	133,576	153,115	280,040
Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense	2,178	3,215	3,495
EARNINGS APPLICABLE TO COMMON STOCK	$ 131,398	$ 149,900	$ 276,545

The common stock of APCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 260,458	$ 717,242	$ 260,439	$ (72,082)	$ 1,166,057
Common Stock Dividends			(128,266)		(128,266)
Preferred Stock Dividends			(1,001)		(1,001)
Capital Stock Expense		2,494	(2,494)		-
SFAS 71 Capitalization		163			163
TOTAL					1,036,953
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $199				351	351
Minimum Pension Liability, Net of Tax of $10,577				19,643	19,643
NET INCOME			280,040		280,040
TOTAL COMPREHENSIVE INCOME					300,034
DECEMBER 31, 2003	260,458	719,899	408,718	(52,088)	1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense		2,415	(2,415)		-
TOTAL					1,286,187
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,176				(7,755)	(7,755)
Minimum Pension Liability, Net of Tax of $11,754				(21,829)	(21,829)
NET INCOME			153,115		153,115
TOTAL COMPREHENSIVE INCOME					123,531
DECEMBER 31, 2004	260,458	722,314	508,618	(81,672)	1,409,718
Capital Contribution From Parent		200,000			200,000
Common Stock Dividends			(5,000)		(5,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense and Other		2,523	(1,378)		1,145
TOTAL					1,605,063
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,821				(7,097)	(7,097)
Minimum Pension Liability, Net of Tax of $38,855				72,159	72,159
NET INCOME			133,576		133,576
TOTAL COMPREHENSIVE INCOME					198,638
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,741	$ 1,543
Accounts Receivable:		
Customers	141,810	126,422
Affiliated Companies	153,453	140,950
Accrued Unbilled Revenues	51,201	51,427
Miscellaneous	527	1,264
Allowance for Uncollectible Accounts	(1,805)	(5,561)
Total Accounts Receivable	345,186	314,502
Fuel	64,657	45,756
Materials and Supplies	54,967	45,644
Risk Management Assets	132,247	81,811
Accrued Tax Benefits	32,979	-
Prepayments and Other	75,129	19,576
TOTAL	706,906	508,832
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,798,157	2,502,273
Transmission	1,266,855	1,255,390
Distribution	2,141,153	2,070,377
Other	323,158	336,051
Construction Work in Progress	647,638	399,116
Total	7,176,961	6,563,207
Accumulated Depreciation and Amortization	2,524,855	2,456,417
TOTAL - NET	4,652,106	4,106,790
OTHER NONCURRENT ASSETS		
Regulatory Assets	457,294	423,407
Long-term Risk Management Assets	176,231	81,245
Deferred Charges and Other	261,556	119,644
TOTAL	895,081	624,296
TOTAL ASSETS	$ 6,254,093	$ 5,239,918

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 194,133	$ 211,060
Accounts Payable:		
General	230,570	133,827
Affiliated Companies	85,941	76,314
Long-term Debt Due Within One Year – Nonaffiliated	146,999	530,010
Customer Deposits	79,854	42,822
Risk Management Liabilities	121,165	89,136
Accrued Taxes	49,833	90,404
Other	108,746	87,118
TOTAL	1,017,241	1,260,691
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,904,379	1,254,588
Long-term Debt – Affiliated	100,000	-
Long-term Risk Management Liabilities	147,117	57,349
Deferred Income Taxes	952,497	852,536
Regulatory Liabilities and Deferred Investment Tax Credits	201,230	201,486
Deferred Credits and Other	110,144	185,766
TOTAL	3,415,367	2,551,725
TOTAL LIABILITIES	4,432,608	3,812,416
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	924,837	722,314
Retained Earnings	635,016	508,618
Accumulated Other Comprehensive Income (Loss)	(16,610)	(81,672)
TOTAL	1,803,701	1,409,718
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,254,093	$ 5,239,918

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 133,576	$ 153,115	$ 280,040
Adjustments for Noncash Items:			
Depreciation and Amortization	190,216	193,525	175,772
Deferred Income Taxes	72,763	47,585	24,563
Cumulative Effect of Accounting Changes, Net of Tax	2,256	-	(77,257)
Carrying Costs Income	(14,438)	(255)	(199)
Mark-to-Market of Risk Management Contracts	(13,701)	5,391	56,409
Pension Contributions to Qualified Plan Trusts	(129,117)	(1,429)	(9,268)
Over/Under Fuel Recovery, Net	(36,499)	(10,861)	74,071
Rate Stabilization Deferral	-	-	(75,601)
Change in Other Noncurrent Assets	(14,097)	(23,228)	(14,520)
Change in Other Noncurrent Liabilities	(13,741)	36,022	47,951
Changes in Components of Working Capital:			
Accounts Receivable, Net	(26,665)	(6,608)	(6,825)
Fuel, Materials and Supplies	(25,419)	(2,795)	8,114
Accounts Payable	61,086	(21,696)	(34,996)
Accrued Taxes, Net	(73,550)	40,145	21,078
Customer Deposits	37,032	8,892	7,744
Other Current Assets	(24,831)	(3,237)	(16,634)
Other Current Liabilities	26,603	(8,242)	(10,594)
Net Cash Flows From Operating Activities	151,474	406,324	449,848
INVESTING ACTIVITIES			
Construction Expenditures	(597,808)	(436,535)	(268,269)
Change in Other Cash Deposits, Net	(24)	41,040	(41,166)
Purchase of Ceredo Generating Station	(100,000)	-	-
Proceeds from Sales of Assets	10,317	3,591	2,192
Net Cash Flows Used For Investing Activities	(687,515)	(391,904)	(307,243)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	200,000	-	-
Issuance of Long-term Debt – Nonaffiliated	840,469	124,398	580,649
Issuance of Long-term Debt – Affiliated	100,000	-	-
Change in Advances from Affiliates, Net	(16,927)	128,066	43,789
Retirement of Long-term Debt – Nonaffiliated	(575,010)	(206,008)	(622,737)
Retirement of Preferred Stock	-	(5,360)	(5,506)
Principal Payments for Capital Lease Obligations	(6,493)	(7,887)	(9,104)
Dividends Paid on Common Stock	(5,000)	(50,000)	(128,266)
Dividends Paid on Cumulative Preferred Stock	(800)	(800)	(1,001)
Net Cash Flows From (Used For) Financing Activities	536,239	(17,591)	(142,176)
Net Increase (Decrease) in Cash and Cash Equivalents	198	(3,171)	429
Cash and Cash Equivalents at Beginning of Period	1,543	4,714	4,285
Cash and Cash Equivalents at End of Period	$ 1,741	$ 1,543	$ 4,714

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was \$91,373,000, \$92,773,000 and \$108,045,000 and for income taxes was \$75,160,000, \$(831,000) and \$62,673,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were \$1,988,000, \$3,791,000 and \$2,332,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of \$82,640,000, \$37,356,000 and \$29,857,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. In connection with the acquisition of Ceredo Generating Station in December 2005, we assumed \$556,000 of liabilities.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,542,332	$ 1,447,925	$ 1,420,549	$ 1,424,583	$ 1,385,932
Operating Income	$ 242,880	$ 258,579	$ 295,412	$ 344,178	$ 362,156
Income Before Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 137,799	$ 140,258	$ 173,147	$ 181,173	$ 191,900
Extraordinary Loss, Net of Tax	-	-	-	-	(30,024)
Cumulative Effect of Accounting Changes, Net of Tax	(839)	-	27,283	-	-
Net Income	$ 136,960	$ 140,258	$ 200,430	$ 181,173	$ 161,876
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 4,026,653	$ 3,717,075	$ 3,598,388	$ 3,497,187	$ 3,387,121
Accumulated Depreciation and Amortization	1,500,858	1,475,457	1,395,113	1,375,035	1,287,222
Net Property, Plant and Equipment	$ 2,525,795	$ 2,241,618	$ 2,203,275	$ 2,122,152	$ 2,099,899
Total Assets	$ 3,432,794	$ 3,029,896	$ 2,838,366	$ 2,849,261	$ 2,815,708
Common Shareholder's Equity	$ 981,546	$ 898,650	$ 897,881	$ 847,664	$ 791,498
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	$ -	$ -	$ -	$ -	$ 10,000
Long-term Debt (a)	$ 1,196,920	$ 987,626	$ 897,564	$ 621,626	$ 791,848
Obligations Under Capital Leases (a)	$ 9,576	$ 12,514	$ 15,618	$ 27,610	$ 34,887

(a) Including portion due within one year.

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 710,000 retail customers in central and southern Ohio. We consolidate Colomet, Inc., Conesville Coal Preparation Company and Simco, Inc., our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of our acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity deficit, expect to incur reduced capacity charges in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

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

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 140
Changes in Gross Margin:		
Retail Margins	31	
Off-system Sales	22	
Transmission Revenues	(13)	
Other Revenues	(7)	
Total Change in Gross Margin		33
Changes in Operating Expenses and Other:		
Asset Impairments and Other Related Charges	(39)	
Depreciation and Amortization	6	
Taxes Other Than Income Taxes	(15)	
Carrying Costs Income	10	
Other Income	2	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(41)
Income Tax Expense		6
Year Ended December 31, 2005		$ 138

Income Before Cumulative Effect of Accounting Changes decreased $2 million to $138 million in 2005. The decrease is primarily due to a $39 million increase in Asset Impairments and Other Related Charges partially offset by an increase in gross margin of $33 million.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins were $31 million higher than the prior period primarily due to favorable weather and lower capacity settlement costs partially offset by lower fuel margins.
- Off-system Sales margins increased $22 million primarily due to increased AEP Power Pool physical sales.
- Transmission Revenues decreased $13 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.
- Other Revenues decreased $7 million primarily due to lower gains on sale of emission allowances.

Operating Expenses and Other changed between years as follows:

- Asset Impairments and Other Related Charges increased $39 million due to the commitment to a plan to retire units 1 and 2 at our Conesville Plant. In September we formally requested permission from PJM to retire the two units effective December 29, 2005. We received final approval on January 1, 2006.
- Depreciation and Amortization expense decreased $6 million primarily due to the Ohio Rate Stabilization Plan order which resulted in a reversal of unused shopping credits of $18 million partially offset by the establishment of a $7 million regulatory liability to benefit low income customers and for economic development and by increased depreciation accruals.
- Taxes Other Than Income Taxes increased $15 million due to an increase in property tax accruals as a result of increased property values. The increase is also a result of increased state excise taxes due to higher taxable KWH sales.

- Carrying Costs Income increased $10 million primarily due to the carrying costs on environmental capital expenditures as a result of the Ohio Rate Stabilization Plan order.
- Interest Expense increased $5 million primarily due to new long-term debt issuances during 2005 and third quarter 2004.

Income Tax

The decrease of $6 million in Income Tax Expense is primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	A-

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period (in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances to Affiliates (a)	$ 17.6	$ -	$ -	$ -	$ 17.6
Interest on Fixed Rate Portion of Long-term Debt (b)	62.9	124.5	109.9	771.3	1,068.6
Fixed Rate Portion of Long-term Debt (c)	-	112.0	250.0	750.0	1,112.0
Variable Rate Portion of Long-term Debt (d)	-	-	-	92.2	92.2
Capital Lease Obligations (e)	3.5	4.9	2.3	-	10.7
Noncancelable Operating Leases (e)	4.1	6.5	4.6	4.0	19.2
Fuel Purchase Contracts (f)	144.0	223.1	78.8	197.0	642.9
Energy and Capacity Purchase Contracts (g)	81.3	34.0	-	-	115.3
Construction Contracts Assets (h)	167.1	-	-	-	167.1
Total	$ 480.5	$ 505.0	$ 445.6	$ 1,814.5	$ 3,245.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.20% and 3.35% at December 31 2005.
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet As of December 31, 2005 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 75,881	$ 626	$ -	$ 76,507
Noncurrent Assets	101,512	-	-	101,512
Total MTM Derivative Contract Assets	177,393	626	-	178,019
Current Liabilities	(66,711)	(1,890)	(435)	(69,036)
Noncurrent Liabilities	(77,360)	(224)	(6,707)	(84,291)
Total MTM Derivative Contract Liabilities	(144,071)	(2,114)	(7,142)	(153,327)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,322	$ (1,488)	$ (7,142)	$ 24,692

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets Year Ended December 31, 2005 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 30,919
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(9,389)
Fair Value of New Contracts at Inception When Entered During the Period (a)	969
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(596)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	11,336
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	83
Total MTM Risk Management Contract Net Assets	33,322
Net Cash Flow Hedge Contracts	(1,488)
DETM Assignment (d)	(7,142)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 24,692

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 3,992	$ 2,235	$ 647	$ -	$ -	$ -	$ 6,874
Prices Provided by Other External Sources – OTC Broker Quotes (a)	10,849	7,421	7,058	3,558	-	-	28,886
Prices Based on Models and Other Valuation Methods (b)	(5,671)	(2,276)	(1,180)	1,897	4,533	259	(2,438)
Total	$ 9,170	$ 7,380	$ 6,525	$ 5,455	$ 4,533	$ 259	$ 33,322

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2004	$ 1,393
Changes in Fair Value	(71)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,181)
Ending Balance in AOCI December 31, 2005	$ (859)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $713 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$424	$705	$335	$121	$332	$1,083	$467	$160

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $86 million and $48 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,413,056	$ 1,340,152	$ 1,310,416
Sales to AEP Affiliates	124,410	104,747	106,307
Other	4,866	3,026	3,826
TOTAL	1,542,332	1,447,925	1,420,549
EXPENSES			
Fuel and Other Consumables for Electric Generation	255,913	211,314	193,378
Fuel from Affiliates for Electric Generation	-	10,603	27,328
Purchased Electricity for Resale	37,012	25,322	17,730
Purchased Electricity from AEP Affiliates	362,959	347,002	337,323
Other Operation	225,896	217,381	204,005
Maintenance	87,303	95,036	75,319
Asset Impairments and Other Related Charges	39,109	-	-
Depreciation and Amortization	142,346	148,529	135,964
Taxes Other Than Income Taxes	148,914	134,159	134,090
TOTAL	1,299,452	1,189,346	1,125,137
OPERATING INCOME	242,880	258,579	295,412
Other Income (Expense):			
Interest Income	3,972	1,993	1,060
Carrying Costs Income	10,367	486	99
Allowance for Equity Funds Used During Construction	1,579	1,117	1,186
Interest Expense	(59,539)	(54,246)	(50,948)
INCOME BEFORE INCOME TAXES	199,259	207,929	246,809
Income Tax Expense	61,460	67,671	73,662
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	137,799	140,258	173,147
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax	(839)	-	27,283
NET INCOME	136,960	140,258	200,430
Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense	2,620	1,015	1,016
EARNINGS APPLICABLE TO COMMON STOCK	$ 134,340	$ 139,243	$ 199,414

The common stock of CSPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 41,026	$ 575,384	$ 290,611	$ (59,357)	$ 847,664
Common Stock Dividends			(163,243)		(163,243)
Capital Stock Expense		1,016	(1,016)		-
TOTAL					684,421
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $253				469	469
Minimum Pension Liability, Net of Tax of $6,763				12,561	12,561
NET INCOME			200,430		200,430
TOTAL COMPREHENSIVE INCOME					213,460
DECEMBER 31, 2003	41,026	576,400	326,782	(46,327)	897,881
Common Stock Dividends			(125,000)		(125,000)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					772,881
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $641				1,191	1,191
Minimum Pension Liability, Net of Tax of $8,443				(15,680)	(15,680)
NET INCOME			140,258		140,258
TOTAL COMPREHENSIVE INCOME					125,769
DECEMBER 31, 2004	41,026	577,415	341,025	(60,816)	898,650
Common Stock Dividends			(114,000)		(114,000)
Capital Stock Expense and Other		2,620	(2,620)		-
TOTAL					784,650
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,212				(2,252)	(2,252)
Minimum Pension Liability, Net of Tax of $33,486				62,188	62,188
NET INCOME			136,960		136,960
TOTAL COMPREHENSIVE INCOME					196,896
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 940	$ 58
Advances to Affiliates	-	141,550
Accounts Receivable:		
Customers	43,143	41,130
Affiliated Companies	67,694	72,854
Accrued Unbilled Revenues	10,086	19,580
Miscellaneous	2,012	1,145
Allowance for Uncollectible Accounts	(1,082)	(674)
Total Accounts Receivable	121,853	134,035
Fuel	28,579	34,026
Materials and Supplies	27,519	21,902
Emission Allowances	20,181	15,235
Risk Management Assets	76,507	46,631
Margin Deposits	16,832	4,848
Accrued Tax Benefits	36,838	-
Prepayments and Other	6,714	10,689
TOTAL	335,963	408,974
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,874,652	1,658,552
Transmission	457,937	432,714
Distribution	1,380,722	1,300,252
Other	184,096	193,814
Construction Work in Progress	129,246	131,743
Total	4,026,653	3,717,075
Accumulated Depreciation and Amortization	1,500,858	1,475,457
TOTAL - NET	2,525,795	2,241,618
OTHER NONCURRENT ASSETS		
Regulatory Assets	231,599	212,003
Long-term Risk Management Assets	101,512	46,735
Deferred Charges and Other	237,925	120,566
TOTAL	571,036	379,304
TOTAL ASSETS	$ 3,432,794	$ 3,029,896

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 17,609	$ -
Accounts Payable:		
General	59,134	64,415
Affiliated Companies	59,399	45,745
Long-term Debt Due Within One Year – Nonaffiliated	-	36,000
Risk Management Liabilities	69,036	42,172
Customer Deposits	47,013	24,890
Accrued Taxes	157,729	195,284
Accrued Interest	18,908	16,320
Other	31,321	27,383
TOTAL	460,149	452,209
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,096,920	851,626
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	84,291	32,731
Deferred Income Taxes	498,232	464,545
Regulatory Liabilities and Deferred Investment Tax Credits	165,344	131,037
Deferred Credits and Other	46,312	99,098
TOTAL	1,991,099	1,679,037
TOTAL LIABILITIES	2,451,248	2,131,246
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value Per Share:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,035	577,415
Retained Earnings	361,365	341,025
Accumulated Other Comprehensive Income (Loss)	(880)	(60,816)
TOTAL	981,546	898,650
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,432,794	$ 3,029,896

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 136,960	$ 140,258	$ 200,430
Adjustments for Noncash Items:			
Depreciation and Amortization	142,346	148,529	135,964
Deferred Income Taxes	19,209	13,395	(4,514)
Cumulative Effect of Accounting Changes, Net of Tax	839	-	(27,283)
Asset Impairment	39,109	-	-
Carrying Costs Income	(10,367)	(486)	(99)
Mark-to-Market of Risk Management Contracts	(8,915)	2,887	41,830
Pension Contributions to Qualified Plan Trusts	(85,871)	(32)	(4,002)
Change in Other Noncurrent Assets	(26,711)	(23,837)	(13,462)
Change in Other Noncurrent Liabilities	9,979	3,904	(14,795)
Changes in Components of Working Capital:			
Accounts Receivable, Net	12,182	9,681	(5,590)
Fuel, Materials and Supplies	2,030	(20,636)	9,681
Accounts Payable	3,075	(1,604)	(64,329)
Accrued Taxes, Net	(78,278)	62,431	20,681
Customer Deposits	22,123	5,163	5,009
Other Current Assets	(12,001)	(7,802)	(12,593)
Other Current Liabilities	5,525	(1,864)	14,257
Net Cash Flows From Operating Activities	171,234	329,987	281,185
INVESTING ACTIVITIES			
Construction Expenditures	(165,452)	(147,102)	(130,331)
Change in Advances to Affiliates, Net	141,550	(141,550)	31,257
Purchase of Waterford Plant	(218,357)	-	-
Purchase of Monongahela Power's Ohio Assets	(41,762)	-	-
Proceeds from Sale of Assets	4,639	3,393	1,644
Net Cash Flows Used For Investing Activities	(279,382)	(285,259)	(97,430)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	244,733	89,883	643,097
Issuance of Long-term Debt – Affiliated	-	100,000	-
Change in Short-term Debt, Net – Affiliated	-	-	(290,000)
Change in Advances from Affiliates, Net	17,609	(6,517)	6,517
Retirement of Long-term Debt – Nonaffiliated	(36,000)	(103,245)	(212,500)
Retirement of Long-term Debt – Affiliated	-	-	(160,000)
Principal Payments for Capital Lease Obligations	(3,312)	(3,933)	(4,962)
Dividends Paid on Common Stock	(114,000)	(125,000)	(163,243)
Net Cash Flows From (Used For) Financing Activities	109,030	(48,812)	(181,091)
Net Increase (Decrease) in Cash and Cash Equivalents	882	(4,084)	2,664
Cash and Cash Equivalents at Beginning of Period	58	4,142	1,478
Cash and Cash Equivalents at End of Period	$ 940	$ 58	$ 4,142

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $54,767,000, $48,461,000 and $42,601,000 and for income taxes was $136,239,000, $(5,282,000) and $63,907,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions in 2005, 2004 and 2003 were $998,000, $1,302,000 and $7,411,000, respectively. Noncash construction expenditures included in Accounts Payable of $11,254,000, $5,955,000 and $6,530,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. In connection with the acquisition of the Waterford Plant in September 2005, we assumed $2,295,000 of liabilities. In connection with the acquisition of Monongahela Power's Ohio assets in December 2005, we assumed $1,839,000 of liabilities.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,892,602	$ 1,741,485	$ 1,650,505	$ 1,609,047	$ 1,615,762
Operating Income	$ 286,660	$ 269,559	$ 204,654	$ 206,825	$ 225,572
Income Before Cumulative Effect of Accounting Change	$ 146,852	$ 133,222	$ 89,548	$ 73,992	$ 75,788
Cumulative Effect of Accounting Change, Net of Tax	-	-	(3,160)	-	-
Net Income	$ 146,852	$ 133,222	$ 86,388	$ 73,992	$ 75,788
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 5,962,282	$ 5,717,480	$ 5,465,207	$ 5,209,982	$ 5,109,424
Accumulated Depreciation and Amortization	2,822,558	2,708,122	2,597,634	2,428,835	2,306,932
Net Property, Plant and Equipment	$ 3,139,724	$ 3,009,358	$ 2,867,573	$ 2,781,147	$ 2,802,492
Total Assets	$ 5,262,309	$ 4,863,222	$ 4,654,171	$ 4,832,832	$ 4,627,610
Common Shareholder's Equity	$ 1,220,092	$ 1,091,498	$ 1,078,047	$ 1,018,653	$ 860,570
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 8,084	$ 8,084	$ 8,101	$ 8,101	$ 8,736
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	$ -	$ 61,445	$ 63,445	$ 64,945	$ 64,945
Long-term Debt (a)	$ 1,444,940	$ 1,312,843	$ 1,339,359	$ 1,617,062	$ 1,652,082
Obligations Under Capital Leases (a)	$ 43,976	$ 50,732	$ 37,843	$ 50,848	$ 61,933

(a) Including portion due within one year.

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 581,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. We consolidate Blackhawk Coal Company and Price River Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives. Our River Transportation Division (RTD) provides barging services to affiliates and nonaffiliated companies. The revenues from barging are the majority of our other revenues.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity surplus, are expecting to receive reduced capacity revenues in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

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

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 133
Changes in Gross Margin:		
Retail Margins	69	
Off-System Sales Margins (a)	7	
Transmission Revenues	(15)	
Other Revenues	4	
Total Change in Gross Margin		65
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(38)	
Taxes Other Than Income Taxes	(11)	
Depreciation and Amortization	1	
Other Income	2	
Interest Expense	4	
Total Change in Operating Expenses and Other		(42)
Income Tax Expense		(9)
Year Ended December 31, 2005		$ 147

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Change increased $14 million to $147 million in 2005. The key drivers of the increase were a $65 million increase in Gross Margin partially offset by a $38 million increase in Other Operation and Maintenance expenses and an $11 million increase in Taxes Other Than Income Taxes.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $69 million primarily due to increases in retail sales to residential and commercial customers and capacity settlement revenues of $39 million under the SIA related to the increase in an affiliate's peak load. Increased retail sales primarily reflect warmer summer weather and colder weather in December 2005. Cooling degree days were approximately 20% higher than normal and approximately 60% higher than 2004. Heating degree days were 13% higher than normal and prior year for December.
- Transmission Revenues decreased $15 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $38 million primarily due to an $18 million increase in power generation maintenance expense due to planned maintenance at Tanners Creek Plant and a $5 million increase in system dispatch cost related to operation in PJM. A $12 million increase in distribution maintenance expense for overhead power lines included the January 2005 ice storm and reliability initiatives.
- Taxes Other Than Income Taxes increased due to a $7 million increase in real and personal property taxes and a $2 million increase in payroll-related taxes.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2003		$ 90
Changes in Gross Margin:		
Retail Margins	34	
Off-system Sales Margins (a)	8	
Other Revenues	11	
Total Change in Gross Margin		53
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	4	
Asset Impairments	10	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	(2)	
Other Income	(5)	
Interest Expense	14	
Total Change in Operating Expenses and Other		20
Income Tax Expense		(30)
Year Ended December 31, 2004		$ 133

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Change increased $43 million to $133 million in 2004. The key driver of the increase was a $53 million increase in Gross Margin.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $34 million primarily due to increases in retail sales to commercial and industrial customers reflecting the economic recovery and the end of amortization of Cook Plant outage settlements.
- Other Revenues increased $11 million primarily due to increased revenues for barging coal to our affiliated companies' plants. Related expenses which offset the revenue increases are included in Other Operation on the Consolidated Statements of Income resulting in RTD earning only its approved return.

Operating Expenses and Other changed between years as follows:

- Asset Impairments decreased due to a $10 million write-down in 2003 of western coal lands (see "Blackhawk Coal Company" section of Note 10).
- Interest Expense decreased $14 million primarily due to a reduction in outstanding long-term debt and lower interest rates from refunding higher cost debt.

Income Taxes

The increase in Income Tax Expense of $30 million is primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 511	$ 3,914	$ 3,237
Cash Flows From (Used For):			
Operating Activities	292,146	510,903	361,793
Investing Activities	(379,593)	(270,964)	(123,131)
Financing Activities	87,790	(243,342)	(237,985)
Net Increase (Decrease) in Cash and Cash Equivalents	343	(3,403)	677
Cash and Cash Equivalents at End of Period	$ 854	$ 511	$ 3,914

Operating Activities

Our net cash flows from operating activities were $292 million in 2005. We produced Net Income of $147 million during the period and noncash expense items of $171 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $118 million change in Accrued Taxes, Net reflecting taxes paid during 2005.

Our net cash flows from operating activities were $511 million in 2004. We produced Net Income of $133 million during the period and noncash expense items of $172 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant relates to Accrued Taxes, Net. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment was made in March 2005 when the 2004 federal income tax return extension was filed.

Our net cash flows from operating activities were $362 million in 2003. We produced Net Income of $86 million during the period and noncash expense items of $171 million for Depreciation and Amortization and $78 million for the Cook Plant outage settlement agreements. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $50 million change in net accounts receivable/payable related to the timing of settlements with our affiliates and $29 million related to Accrued Taxes, Net related to the timing of estimated federal income tax payments.

Investing Activities

Cash flows used for investing activities during 2005, 2004 and 2003 primarily reflect our construction expenditures of $299 million, $179 million and $163 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. We also invested in capital projects to improve air quality and water intake systems.

Financing Activities

Our cash flows from financing activities were $88 million in 2005. We issued long-term debt and borrowed from our affiliates to fund construction expenditures.

Our cash flows used for financing activities were $243 million in 2004. We used cash from operations to repay short-term debt and pay common dividends. In 2004, we issued $175 million in senior unsecured notes and refunded $97 million in fixed rate installment purchase contracts and reissued at a variable rate.

Financing activities for 2003 used $238 million of cash from operations primarily to redeem $285 million of long-term debt using short-term debt and refinanced $65 million of our installment purchase contracts at a lower fixed rate through October 2006.

Off-Balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

Rockport Plant Unit 2

In 1989, AEGCo and I&M, co-owners of Rockport Plant Unit 1, entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (Rockport 2). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1.3 billion as of December 31, 2005.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns Rockport 2 and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell Rockport 2. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period (in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 93.7	$ -	$ -	$ -	$ 93.7
Interest on Fixed Rate Portion of Long-term Debt (b)	60.1	76.0	69.1	328.9	534.1
Fixed Rate Portion of Long-term Debt (c)	364.5	100.0	-	835.8	1,300.3
Variable Rate Portion of Long-term Debt (d)	-	-	45.0	102.0	147.0
Capital Lease Obligations (e)	9.2	21.1	6.5	20.7	57.5
Noncancelable Operating Leases (e)	100.7	194.1	186.3	949.8	1,430.9
Fuel Purchase Contracts (f)	255.3	330.1	265.4	204.8	1,055.6
Energy and Capacity Purchase Contracts (g)	0.4	0.2	-	-	0.6
Construction Contracts for Capital Assets (h)	95.8	33.1	-	-	128.9
Total	$ 979.7	$ 754.6	$ 572.3	$ 2,442.0	$ 4,748.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had an interest rate of 3.23% at December 31, 2005.
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our Consolidated Balance Sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheet
As of December 31, 2005
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 77,494	$ 640	$ -	$ 78,134
Noncurrent Assets	103,645	-	-	103,645
Total MTM Derivative Contract Assets	181,139	640	-	181,779
Current Liabilities	(68,126)	(2,462)	(444)	(71,032)
Noncurrent Liabilities	(79,081)	(228)	(6,850)	(86,159)
Total MTM Derivative Contract Liabilities	(147,207)	(2,690)	(7,294)	(157,191)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,932	$ (2,050)	$ (7,294)	$ 24,588

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 34,573
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	331
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(734)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	545
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(783)
Total MTM Risk Management Contract Net Assets	33,932
Net Cash Flow & Fair Value Hedge Contracts	(2,050)
DETM Assignment (d)	(7,294)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 24,588

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in our Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 4,077	$ 2,282	$ 660	$ -	$ -	$ -	$ 7,019
Prices Provided by Other External Sources – OTC Broker Quotes (a)	11,125	7,556	7,206	3,635	-	-	29,522
Prices Based on Models and Other Valuation Methods (b)	(5,834)	(2,358)	(1,249)	1,938	4,630	264	(2,609)
Total	$ 9,368	$ 7,480	$ 6,617	$ 5,573	$ 4,630	$ 264	$ 33,932

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)
Changes in Fair Value	(5)	2,494	2,489
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,430)	550	(1,880)
Ending Balance in AOCI December 31, 2005	$ (877)	$ (2,590)	$ (3,467)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,050 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$433	$720	$343	$124	$371	$1,211	$522	$178

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $55 million and $53 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,445,866	$ 1,378,844	$ 1,302,269
Sales to AEP Affiliates	366,032	286,310	283,094
Other – Affiliated	46,719	42,968	34,972
Other – Nonaffiliated	33,985	33,363	30,170
TOTAL	1,892,602	1,741,485	1,650,505
EXPENSES			
Fuel and Other Consumables for Electric Generation	327,263	286,211	255,395
Purchased Electricity for Resale	48,378	37,013	28,327
Purchased Electricity from AEP Affiliates	306,117	272,452	274,400
Other Operation	476,560	473,234	487,712
Maintenance	202,909	168,304	158,281
Asset Impairments	-	-	10,300
Depreciation and Amortization	171,030	172,099	171,281
Taxes Other Than Income Taxes	73,685	62,613	60,155
TOTAL	1,605,942	1,471,926	1,445,851
OPERATING INCOME	286,660	269,559	204,654
Other Income (Expense):			
Interest Income	2,006	2,011	4,006
Allowance for Equity Funds Used During Construction	4,457	2,338	5,090
Interest Expense	(65,041)	(69,071)	(83,054)
INCOME BEFORE INCOME TAXES	228,082	204,837	130,696
Income Tax Expense	81,230	71,615	41,148
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	146,852	133,222	89,548
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, Net of Tax	-	-	(3,160)
NET INCOME	146,852	133,222	86,388
Preferred Stock Dividend Requirements including Capital Stock Expense	395	474	2,509
EARNINGS APPLICABLE TO COMMON STOCK	$ 146,457	$ 132,748	$ 83,879

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 56,584	$ 858,560	$ 143,996	$ (40,487)	$ 1,018,653
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(2,375)		(2,375)
Capital Stock Expense		134	(134)		-
TOTAL					976,278
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $273				508	508
Minimum Pension Liability, Net of Tax of $8,009				14,873	14,873
NET INCOME			86,388		86,388
TOTAL COMPREHENSIVE INCOME					101,769
DECEMBER 31, 2003	56,584	858,694	187,875	(25,106)	1,078,047
Common Stock Dividends			(99,293)		(99,293)
Preferred Stock Dividends			(340)		(340)
Capital Stock Expense		141	(134)		7
TOTAL					978,421
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,314				(4,298)	(4,298)
Minimum Pension Liability, Net of Tax of $8,533				(15,847)	(15,847)
NET INCOME			133,222		133,222
TOTAL COMPREHENSIVE INCOME					113,077
DECEMBER 31, 2004	56,584	858,835	221,330	(45,251)	1,091,498
Common Stock Dividends			(62,000)		(62,000)
Preferred Stock Dividends			(339)		(339)
Capital Stock Expense and Other		2,455	(56)		2,399
TOTAL					1,031,558
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $328				609	609
Minimum Pension Liability, Net of Tax of $22,116				41,073	41,073
NET INCOME			146,852		146,852
TOTAL COMPREHENSIVE INCOME					188,534
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 854	$ 511
Advances to Affiliates	-	5,093
Accounts Receivable:		
Customers	62,614	62,608
Affiliated Companies	127,981	124,134
Miscellaneous	1,982	4,339
Allowance for Uncollectible Accounts	(898)	(187)
Total Accounts Receivable	191,679	190,894
Fuel	25,894	27,218
Materials and Supplies	118,039	103,342
Risk Management Assets	78,134	52,141
Accrued Tax Benefits	51,846	-
Margin Deposits	17,115	5,400
Prepayments and Other	14,188	11,295
TOTAL	497,749	395,894
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,128,078	3,122,883
Transmission	1,028,496	1,009,551
Distribution	1,029,498	990,826
Other (including nuclear fuel and coal mining)	465,130	430,705
Construction Work in Progress	311,080	163,515
Total	5,962,282	5,717,480
Accumulated Depreciation, Depletion and Amortization	2,822,558	2,708,122
TOTAL - NET	3,139,724	3,009,358
OTHER NONCURRENT ASSETS		
Regulatory Assets	222,686	251,090
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,133,567	1,053,439
Long-term Risk Management Assets	103,645	52,256
Deferred Charges and Other	164,938	101,185
TOTAL	1,624,836	1,457,970
TOTAL ASSETS	$ 5,262,309	$ 4,863,222

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 93,702	$ -
Accounts Payable:		
General	139,334	92,916
Affiliated Companies	60,324	51,066
Long-term Debt Due Within One Year	364,469	-
Cumulative Preferred Stock Due Within One Year	-	61,445
Risk Management Liabilities	71,032	47,174
Customer Deposits	49,258	29,366
Accrued Taxes	56,567	123,159
Other	112,839	87,363
TOTAL	947,525	492,489
NONCURRENT LIABILITIES		
Long-term Debt	1,080,471	1,312,843
Long-term Risk Management Liabilities	86,159	36,815
Deferred Income Taxes	335,264	315,730
Regulatory Liabilities and Deferred Investment Tax Credits	710,015	677,260
Asset Retirement Obligations	737,959	711,769
Deferred Credits and Other	136,740	216,734
TOTAL	3,086,608	3,271,151
TOTAL LIABILITIES	4,034,133	3,763,640
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,290	858,835
Retained Earnings	305,787	221,330
Accumulated Other Comprehensive Income (Loss)	(3,569)	(45,251)
TOTAL	1,220,092	1,091,498
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,262,309	$ 4,863,222

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 146,852	$ 133,222	$ 86,388
Adjustments for Noncash Items:			
Depreciation and Amortization	171,030	172,099	171,281
Accretion of Asset Retirement Obligations	47,368	39,825	37,150
Deferred Income Taxes	26,873	(5,548)	(14,894)
Deferred Investment Tax Credits	(7,725)	(7,476)	(7,431)
Cumulative Effect of Accounting Change, Net of Tax	-	-	3,160
Asset Impairments	-	-	10,300
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	21,273	13,082	(27,754)
Amoritization of Nuclear Fuel	56,038	52,455	44,276
Amortization of Cook Plant Outage Costs	-	-	40,000
Mark-to-Market of Risk Management Contracts	(7,331)	2,756	43,938
Pension Contributions to Qualified Plan Trusts	(90,668)	(3,888)	(9,437)
Unrecovered Fuel and Purchased Power Costs	(1,681)	(1,689)	37,501
Change in Other Noncurrent Assets	37,997	24,736	40,481
Change in Other Noncurrent Liabilities	(17,355)	8,526	16,444
Changes in Components of Working Capital:			
Accounts Receivable, Net	(785)	983	34,346
Fuel, Materials and Supplies	(13,373)	(10,977)	(7,320)
Accounts Payable	9,630	(1,304)	(85,312)
Accrued Taxes, Net	(118,438)	80,970	(29,370)
Customer Deposits	19,892	7,411	5,294
Other Current Assets	(12,927)	(478)	(3,353)
Other Current Liabilities	25,476	6,198	(23,895)
Net Cash Flows From Operating Activities	292,146	510,903	361,793
INVESTING ACTIVITIES			
Construction Expenditures	(298,632)	(179,414)	(163,391)
Change in Advances to Affiliates, Net	5,093	(5,093)	191,226
Purchases of Investment Securities	(606,936)	(901,356)	(656,557)
Sales of Investment Securities	556,667	862,976	579,932
Acquisitions of Nuclear Fuel	(52,579)	(50,865)	(76,177)
Proceeds from Sale of Assets	16,794	2,788	1,836
Net Cash Flows Used For Investing Activities	(379,593)	(270,964)	(123,131)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	123,761	268,057	64,434
Change in Advances from Affiliates, Net	93,702	(98,822)	98,822
Retirement of Long-term Debt	-	(304,017)	(350,000)
Retirement of Cumulative Preferred Stock	(61,445)	(2,011)	(1,500)
Principal Payments for Capital Lease Obligations	(5,889)	(6,916)	(7,366)
Dividends Paid on Common Stock	(62,000)	(99,293)	(40,000)
Dividends Paid on Cumulative Preferred Stock	(339)	(340)	(2,375)
Net Cash Flows From (Used For) Financing Activities	87,790	(243,342)	(237,985)
Net Increase (Decrease) in Cash and Cash Equivalents	343	(3,403)	677
Cash and Cash Equivalents at Beginning of Period	511	3,914	3,237
Cash and Cash Equivalents at End of Period	$ 854	$ 511	$ 3,914

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $59,339,000, $70,988,000 and $82,593,000 and for income taxes was $184,061,000, and $(2,244,000) and $94,440,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $2,639,000, $20,557,000 and $3,216,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $38,523,000, $16,530,000 and $21,487,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. Noncash acquisition of nuclear fuel included in Accounts Payable was $24,053,000 as of December 31, 2005.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 531,343	$ 448,961	$ 412,667	$ 391,516	$ 394,021
Operating Income	$ 60,831	$ 63,339	$ 70,749	$ 57,579	$ 58,824
Income Before Cumulative Effect of Accounting Change	$ 20,809	$ 25,905	$ 33,464	$ 20,567	$ 21,565
Cumulative Effect of Accounting Change, Net of Tax	-	-	(1,134)	-	-
Net Income	$ 20,809	$ 25,905	$ 32,330	$ 20,567	$ 21,565
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,414,426	$ 1,367,138	$ 1,355,315	$ 1,301,332	$ 1,134,149
Accumulated Depreciation and Amortization	425,817	398,608	382,022	373,874	360,531
Net Property, Plant and Equipment	$ 988,609	$ 968,530	$ 973,293	$ 927,458	$ 773,618
Total Assets	$ 1,320,026	$ 1,243,247	$ 1,221,634	$ 1,188,342	$ 1,022,833
Long-term Debt (a)	$ 486,990	$ 508,310	$ 487,602	$ 466,632	$ 346,093
Common Shareholder's Equity	$ 347,841	$ 320,980	$ 317,138	$ 298,018	$ 256,130
Obligations Under Capital Leases (a)	$ 3,168	$ 4,363	$ 5,292	$ 7,248	$ 9,583

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity deficit, expect to incur increased capacity charges in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

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

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Income Taxes

The increase in income tax expense of $3 million is primarily due to the recording of the tax return adjustments.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 6.0	$ -	$ -	$ -	$ 6.0
Interest on Long-term Debt (b)	25.2	31.3	10.5	97.5	164.5
Long-term Debt (c)	39.8	352.4	-	95.0	487.2
Capital Lease Obligations (d)	1.3	1.7	0.4	0.1	3.5
Noncancelable Operating Leases (d)	1.8	2.8	2.1	2.0	8.7
Fuel Purchase Contracts (e)	128.2	75.9	-	-	204.1
Energy and Capacity Purchase Contracts (f)	0.1	0.1	-	-	0.2
Construction Contracts for Capital Assets (g)	32.5	-	-	-	32.5
Total	$ 234.9	$ 464.2	$ 13.0	$ 194.6	$ 906.7

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 15.
(e) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

**Reconciliation of MTM Risk Management Contracts to Balance Sheet
As of December 31, 2005
(in thousands)**

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 31,180	$ 257	$ -	$ 31,437
Noncurrent Assets	41,810	-	-	41,810
Total MTM Derivative Contract Assets	72,990	257	-	73,247
Current Liabilities	(27,586)	(1,005)	(179)	(28,770)
Noncurrent Liabilities	(31,886)	(663)	(2,753)	(35,302)
Total MTM Derivative Contract Liabilities	(59,472)	(1,668)	(2,932)	(64,072)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 13,518	$ (1,411)	$ (2,932)	$ 9,175

(a) See "Natural Gas Contracts with DETM" section of Note 17.

**MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)**

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 12,691
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	73
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(337)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	443
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	648
Total MTM Risk Management Contract Net Assets	13,518
Net Cash Flow & Fair Value Hedge Contracts	(1,411)
DETM Assignment (d)	(2,932)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 9,175

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,639	$ 917	$ 265	$ -	$ -	$ -	$ 2,821
Prices Provided by Other External Sources – OTC Broker Quotes (a)	4,324	3,116	2,907	1,461	-	-	11,808
Prices Based on Models and Other Valuation Methods (b)	(2,369)	(965)	(522)	778	1,861	106	(1,111)
Total	$ 3,594	$ 3,068	$ 2,650	$ 2,239	$ 1,861	$ 106	$ 13,518

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 569	$ 244	$ 813
Changes in Fair Value	81	-	81
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(1,002)	(86)	(1,088)
Ending Balance in AOCI December 31, 2005	$ (352)	$ 158	$ (194)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $207 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$174	$289	$138	$50	$135	$442	$191	$65

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $13 million and $16 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 458,858	$ 397,581	$ 361,198
Sales to AEP Affiliates	70,803	48,717	49,466
Other	1,682	2,663	2,003
TOTAL	531,343	448,961	412,667
EXPENSES			
Fuel and Other Consumables for Electric Generation	142,672	103,881	78,974
Purchased Electricity for Resale	7,213	3,407	963
Purchased Electricity from AEP Affiliates	176,350	140,758	141,690
Other Operation	59,024	51,782	44,866
Maintenance	30,652	32,802	27,328
Depreciation and Amortization	45,110	43,847	39,309
Taxes Other Than Income Taxes	9,491	9,145	8,788
TOTAL	470,512	385,622	341,918
OPERATING INCOME	60,831	63,339	70,749
Other Income (Expense):			
Interest Income	880	462	39
Allowance for Equity Funds Used During Construction	305	245	971
Interest Expense	(29,071)	(29,470)	(28,620)
INCOME BEFORE INCOME TAXES	32,945	34,576	43,139
Income Tax Expense	12,136	8,671	9,675
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	20,809	25,905	33,464
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, Net of Tax	-	-	(1,134)
NET INCOME	$ 20,809	$ 25,905	$ 32,330

The common stock of KPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 50,450	$ 208,750	$ 48,269	$ (9,451)	$ 298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $53				98	98
Minimum Pension Liability, Net of Tax of $1,691				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	50,450	208,750	64,151	(6,213)	317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL					297,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $212				393	393
Minimum Pension Liability, Net of Tax of $1,592				(2,955)	(2,955)
NET INCOME			25,905		25,905
TOTAL COMPREHENSIVE INCOME					23,343
DECEMBER 31, 2004	50,450	208,750	70,555	(8,775)	320,980
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	$ 50,450	$ 208,750	$ 88,864	$ (223)	$ 347,841

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 526	$ 132
Advances to Affiliates	-	16,127
Accounts Receivable:		
Customers	26,533	22,130
Affiliated Companies	23,525	23,046
Accrued Unbilled Revenues	6,311	7,340
Miscellaneous	35	94
Allowance for Uncollectible Accounts	(147)	(34)
Total Accounts Receivable	56,257	52,576
Fuel	8,490	6,551
Materials and Supplies	10,181	9,385
Risk Management Assets	31,437	19,845
Margin Deposits	6,895	1,960
Accrued Tax Benefits	6,598	-
Prepayments and Other	6,324	1,993
TOTAL	126,708	108,569
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	472,575	462,641
Transmission	386,945	385,667
Distribution	456,063	438,766
Other	63,382	63,520
Construction Work in Progress	35,461	16,544
Total	1,414,426	1,367,138
Accumulated Depreciation and Amortization	425,817	398,608
TOTAL - NET	988,609	968,530
OTHER NONCURRENT ASSETS		
Regulatory Assets	117,432	118,407
Long-term Risk Management Assets	41,810	19,067
Deferred Charges and Other	45,467	28,674
TOTAL	204,709	166,148
TOTAL ASSETS	$ 1,320,026	$ 1,243,247

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2005 and 2004

	2005	2004
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 6,040	$ -
Accounts Payable:		
General	32,454	20,080
Affiliated Companies	29,326	24,899
Long-term Debt Due Within One Year – Affiliated	39,771	-
Risk Management Liabilities	28,770	17,205
Customer Deposits	21,643	12,309
Accrued Taxes	8,805	9,248
Other	21,524	19,935
TOTAL	188,333	103,676
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	427,219	428,310
Long-term Debt – Affiliated	20,000	80,000
Long-term Risk Management Liabilities	35,302	13,484
Deferred Income Taxes	234,719	227,536
Regulatory Liabilities and Deferred Investment Tax Credits	56,794	47,994
Deferred Credits and Other	9,818	21,267
TOTAL	783,852	818,591
TOTAL LIABILITIES	972,185	922,267
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $50 Par Value Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	88,864	70,555
Accumulated Other Comprehensive Income (Loss)	(223)	(8,775)
TOTAL	347,841	320,980
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,320,026	$ 1,243,247

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 20,809	$ 25,905	$ 32,330
Adjustments for Noncash Items:			
Depreciation and Amortization	45,110	43,847	39,309
Deferred Income Taxes	10,555	12,774	20,107
Cumulative Effect of Accounting Change, Net of Tax	-	-	1,134
Mark-to-Market of Risk Management Contracts	(3,465)	1,020	15,112
Pension Contributions to Qualified Plan Trusts	(18,894)	(451)	(1,614)
Change in Other Noncurrent Assets	(419)	(6,902)	(16,613)
Change in Other Noncurrent Liabilities	3,844	9,126	8,720
Changes in Components of Working Capital:			
Accounts Receivable, Net	(3,681)	(1,177)	2,445
Fuel, Materials and Supplies	(2,735)	2,724	1,077
Accounts Payable	13,184	(1,745)	(31,000)
Accrued Taxes, Net	(7,041)	1,919	8,582
Customer Deposits	9,334	2,415	1,846
Other Current Assets	(9,261)	474	(1,055)
Other Current Liabilities	1,589	65	(3,505)
Net Cash Flows From Operating Activities	58,929	89,994	76,875
INVESTING ACTIVITIES			
Construction Expenditures	(56,979)	(36,957)	(94,836)
Change in Other Cash Deposits, Net	(5)	-	-
Change in Advances to Affiliates, Net	16,127	(16,127)	-
Proceeds from Sale of Assets	300	1,538	967
Net Cash Flows Used For Investing Activities	(40,557)	(51,546)	(93,869)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	-	74,263
Issuance of Long-term Debt – Affiliated	-	20,000	-
Change in Advances from Affiliates, Net	6,040	(38,096)	14,710
Retirement of Long-term Debt – Nonaffiliated	-	-	(40,000)
Retirement of Long-term Debt – Affiliated	(20,000)	-	(15,000)
Principal Payments for Capital Lease Obligations	(1,518)	(1,605)	(1,949)
Dividends Paid on Common Stock	(2,500)	(19,501)	(16,448)
Net Cash Flows From (Used For) Financing Activities	(17,978)	(39,202)	15,576
Net Increase (Decrease) in Cash and Cash Equivalents	394	(754)	(1,418)
Cash and Cash Equivalents at Beginning of Period	132	886	2,304
Cash and Cash Equivalents at End of Period	$ 526	$ 132	$ 886

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $27,354,000, $28,367,000 and $26,988,000 and for income taxes was $11,655,000, $(3,233,000) and $(17,574,000) in 2005, 2004 and 2003, respectively. Noncash acquisitions under capital leases were $419,000, $925,000 and $344,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $6,553,000, $2,936,000 and $1,662,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to KPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2005 and 2004, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 11 to the financial statements, respectively, the Company adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 2,634,549	$ 2,372,725	$ 2,250,132	$ 2,163,082	$ 2,153,150
Operating Income	$ 425,487	$ 419,539	$ 491,844	$ 433,983	$ 349,533
Income Before Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 250,419	$ 210,116	$ 251,031	$ 220,023	$ 165,793
Extraordinary Loss, Net of Tax	-	-	-	-	(18,348)
Cumulative Effect of Accounting Changes, Net of Tax	(4,575)	-	124,632	-	-
Net Income	$ 245,844	$ 210,116	$ 375,663	$ 220,023	$ 147,445
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 7,523,288	$ 6,858,771	$ 6,575,577	$ 5,732,008	$ 5,436,218
Accumulated Depreciation and Amortization	2,738,899	2,633,203	2,500,918	2,486,982	2,374,377
Net Property, Plant and Equipment	$ 4,784,389	$ 4,225,568	$ 4,074,659	$ 3,245,026	$ 3,061,841
Total Assets (b)	$ 6,330,670	$ 5,593,265	$ 5,374,518	$ 4,554,023	$ 4,485,787
Common Shareholder's Equity	$ 1,767,947	$ 1,473,838	$ 1,464,025	$ 1,233,114	$ 1,184,785
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 16,639	$ 16,641	$ 16,645	$ 16,648	$ 16,648
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	$ -	$ 5,000	$ 7,250	$ 8,850	$ 8,850
Long-term Debt (a)(b)	$ 2,199,670	$ 2,011,060	$ 2,039,940	$ 1,067,314	$ 1,203,841
Obligations Under Capital Leases (a)	$ 39,924	$ 40,733	$ 34,688	$ 65,626	$ 80,666

(a) Including portion due within one year.
(b) Due to the implementation of FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003.

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We consolidate JMG Funding LP, a variable interest entity. As a member of the AEP Power Pool, we share in the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity excess, expect to receive reduced capacity revenues in 2006. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

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

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Effective July 1, 2003, we consolidated JMG as a result of the implementation of FIN 46. OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected. See "Gavin Scrubber Financing Arrangement" section of Note 15.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 210
Changes in Gross Margin:		
Retail Margins	35	
Off-system Sales	45	
Transmission Revenues	(15)	
Other Revenues	1	
Total Change in Gross Margin		66
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(32)	
Depreciation and Amortization	(16)	
Taxes Other Than Income Taxes	(12)	
Carrying Costs Income	48	
Interest Expense	15	
Total Change in Operating Expenses and Other		3
Income Tax Expense		(29)
Year Ended December 31, 2005		$ 250

Income Before Cumulative Effect of Accounting Changes increased by $40 million in 2005. The key drivers of the increase were a $66 million increase in Gross Margin and a $48 million increase in Carrying Costs Income partially offset by a $32 million increase in Other Operation and Maintenance expenses and a $29 million increase in Income Tax Expense.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins were $35 million higher than the prior period primarily due to:
  - increased retail sales of $44 million due to increased residential, commercial and industrial sales from higher usage and favorable weather conditions,
  - a favorable variance of $18 million from the receipt of SO_2 allowances from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement,
  - and an increase of $7 million from capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak,
  - partially offset by decreased fuel margins of $18 million which includes an amendment to the PJM Services and Cost Allocation Agreement and the Buckeye Station Agreement of $9 million.
- Margins from Off-system Sales increased $45 million primarily due to increased AEP Power Pool physical sales.

- Transmission Revenues decreased $15 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenues" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $32 million primarily due to increased planned outages and maintenance on several units, maintenance of overhead lines due to increased tree trimming expenses and decreased expenses in 2004 as a result of a settlement related to the sale of the coal companies prior to 2003. These increases were partially offset by the settlement and cancellation of the COLI (corporate owned life insurance) policy in February 2005 and decreased administrative expenses related to the Gavin scrubber.
- Depreciation and Amortization expense increased $16 million due to the establishment of a $7 million regulatory liability to benefit low-income customers and for economic development, as ordered in the Ohio Rate Stabilization Plan. The increase is also attributable to a higher depreciation base in electric utility plants.
- Taxes Other Than Income Taxes increased $12 million primarily due to an increase in property tax accruals as a result of increased property values. The increase is also a result of increased state excise taxes due to higher taxable KWH sales.
- Carrying Costs Income increased $48 million primarily due to the carrying costs on environmental capital expenditures as a result of the Ohio Rate Stabilization Plan order.
- Interest Expense decreased $15 million primarily due to capitalized interest related to construction of the Mitchell Plant and Cardinal Plant scrubbers and the Mitchell Plant SCR project that began after June 2004. Interest Expense also decreased due to optional redemptions and subsequent refinancings with lower cost debt.

Income Taxes

The increase of $29 million in Income Tax Expense is primarily due to an increase in pretax book income.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ 251
Changes in Gross Margin:		
Retail Margins	(29)	
Off-system Sales	30	
Transmission Revenues	(5)	
Other Revenues	(18)	
Total Change in Gross Margin		(22)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(19)	
Depreciation and Amortization	(29)	
Taxes Other Than Income Taxes	(2)	
Other Income	1	
Interest Expense	(12)	
Total Change in Operating Expenses and Other		(61)
Income Tax Expense		42
Year Ended December 31, 2004		$ 210

Income Before Cumulative Effect of Accounting Changes decreased by $41 million in 2004. The key drivers of the decrease were a $22 million decrease in gross margin, a $29 million increase in Depreciation and Amortization and a $19 million increase in Other Operation and Maintenance expenses partially offset by a $42 million decrease in Income Tax Expense.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins were $29 million lower than the prior period primarily due to higher fuel costs.
- Margins from Off-system Sales increased $30 million primarily due to favorable optimization activity.
- Other Revenues decreased by $18 million primarily due to 2003 recovery of employee benefits, reclamation and other charges as a result of a settlement related to the sale of the coal companies prior to 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $19 million primarily due to expense associated with costs incurred as a result of a major ice storm in December 2004 and increased employee benefit expenses including pension plan costs and workers' compensation expenses.
- A $29 million increase in Depreciation and Amortization expense primarily associated with the consolidation of JMG (there was no change in Net Income due to the consolidation of JMG). In addition, the increase is a result of a greater depreciable asset base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
- Interest Expense increased $12 million primarily due to the consolidation of JMG in July 2003 and its associated debt. There was no change in Net Income due to the consolidation of JMG.

Income Taxes

The decrease of $42 million in Income Tax Expense is primarily due to a decrease in pretax book income, the recording of the tax return and tax reserve adjustments, and a decrease in state and local income taxes.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the years ended December 31, 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 9,337	$ 7,294	$ 5,285
Cash Flows From (Used For):			
Operating Activities	368,805	545,855	391,989
Investing Activities	(571,184)	(324,392)	(365,207)
Financing Activities	194,282	(219,420)	(24,773)
Net Increase (Decrease) in Cash and Cash Equivalents	(8,097)	2,043	2,009
Cash and Cash Equivalents at End of Period	$ 1,240	$ 9,337	$ 7,294

Operating Activities

Our net cash flows from operating activities were $369 million in 2005. We produced income of $246 million during the period and a noncash expense item of $302 million for Depreciation and Amortization. We made contributions of $132 million to our pension trust fund. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(114) million change in Accrued Taxes, Net. During 2005, we made federal income tax payments of $198 million.

Our net cash flows from operating activities were $546 million in 2004. We produced income of $210 million during the period and noncash expense items of $286 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $100 million change in Accrued Taxes, Net. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment was made in March 2005 when the 2004 federal income tax return extension was filed.

Our net cash flows from operating activities were $392 million in 2003. We produced income of $376 million during the period and noncash expense items of $257 million for Depreciation and Amortization and $(125) million for Cumulative Effect of Accounting Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(163) million change in Accounts Payable. The change is a result of significant reductions of accounts payable balances partially associated with a wind down of the optimization activities during 2003.

Investing Activities

Our net cash flows used for investing activities in 2005, 2004 and 2003 were $571 million, $324 million and $365 million, respectively, primarily due to Construction Expenditures for environmental upgrades, as well as projects to improve service reliability for transmission and distribution.

Financing Activities

Our net cash flows from financing activities in 2005 were $194 million primarily due to issuances of long-term debt offset by a long-term debt retirement as well as decreased dividend payments on common stock of $144 million.

Our net cash flows used for financing activities in 2004 were $219 million primarily due to retirement of long-term debt and payment of dividends on common stock offset by a long-term debt issuance from AEP.

Our net cash flows used for financing activities in 2003 were $25 million due to replacing both short and long-term debt with proceeds from new borrowings.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 10.4	$ -	$ -	$ -	$ 10.4
Advances from Affiliates (b)	70.1	-	-	-	70.1
Interest on Fixed Rate Portion of Long-term Debt (c)	94.9	181.2	165.3	887.9	1,329.3
Fixed Rate Portion of Long-term Debt (d)	212.4	73.0	277.5	1,239.1	1,802.0
Variable Rate Portion of Long-term Debt (e)	-	-	-	403.0	403.0
Capital Lease Obligations (f)	10.1	14.5	8.0	22.5	55.1
Noncancelable Operating Leases (f)	17.9	32.9	28.6	65.5	144.9
Fuel Purchase Contracts (g)	614.5	1,252.2	1,402.9	4,827.5	8,097.1
Energy and Capacity Purchase Contracts (h)	47.8	96.4	112.7	289.2	546.1
Construction Contracts for Capital Assets (i)	365.8	168.0	-	-	533.8
Total	$ 1,443.9	$ 1,818.2	$ 1,995.0	$ 7,734.7	$ 12,991.8

(a) Represents principal only excluding interest.
(b) Represents short-term borrowing from the Utility Money Pool.
(c) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(d) See Note 16. Represents principal only excluding interest.
(e) See Note 16. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.10% and 3.45% at December 31, 2005.
(f) See Note 15.
(g) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(h) Represents contractual cash flows of energy and capacity purchase contracts.
(i) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet As of December 31, 2005 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 108,029	$ 6,991	$ -	$ 115,020
Noncurrent Assets	144,015	-	-	144,015
Total MTM Derivative Contract Assets	252,044	6,991	-	259,035
Current Liabilities	(101,422)	(6,777)	(598)	(108,797)
Noncurrent Liabilities	(109,728)	(307)	(9,212)	(119,247)
Total MTM Derivative Contract Liabilities	(211,150)	(7,084)	(9,810)	(228,044)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 40,894	$ (93)	$ (9,810)	$ 30,991

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets Year Ended December 31, 2005 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 47,777
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(16,803)
Fair Value of New Contracts at Inception When Entered During the Period (a)	1,343
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(2,358)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	10,821
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	114
Total MTM Risk Management Contract Net Assets	40,894
Net Cash Flow Hedge Contracts	(93)
DETM Assignment (d)	(9,810)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 30,991

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – ExchangeTraded Contracts	$ 6,061	$ 3,069	$ 888	$ -	$ -	$ -	$ 10,018
Prices Provided by Other External Sources – OTC Broker Quotes (a)	9,153	12,354	9,976	4,888	-	-	36,371
Prices Based on Models and OtherValuation Methods (b)	(8,607)	(3,770)	(2,304)	2,605	6,226	355	(5,495)
Total	$ 6,607	$ 11,653	$ 8,560	$ 7,493	$ 6,226	$ 355	$ 40,894

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 1,599	$ (358)	$ -	$ 1,241
Changes in Fair Value	700	-	1,581	2,281
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,691)	14	(90)	(2,767)
Ending Balance in AOCI December 31, 2005	$ (392)	$ (344)	$ 1,491	$ 755

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $332 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)			
End	High	Average	Low
$583	$968	$461	$166

December 31, 2004 (in thousands)			
End	High	Average	Low
$464	$1,513	$652	$223

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $111 million and $146 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

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OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,922,280	$ 1,752,766	$ 1,612,301
Sales to AEP Affiliates	681,852	594,357	600,803
Other - Affiliated	15,437	15,013	13,233
Other - Nonaffiliated	14,980	10,589	23,795
TOTAL	2,634,549	2,372,725	2,250,132
EXPENSES			
Fuel and Other Consumables for Electric Generation	975,180	819,787	674,607
Purchased Electricity for Resale	77,173	64,229	63,486
Purchased Electricity from AEP Affiliates	116,890	89,355	90,821
Other Operation	340,085	336,330	329,725
Maintenance	207,226	179,290	166,438
Depreciation and Amortization	302,495	286,300	257,417
Taxes Other Than Income Taxes	190,013	177,895	175,794
TOTAL	2,209,062	1,953,186	1,758,288
OPERATING INCOME	425,487	419,539	491,844
Other Income (Expense):			
Interest Income	3,311	3,155	2,365
Carrying Costs Income	48,510	735	592
Allowance for Equity Funds Used During Construction	1,441	1,482	1,093
Interest Expense	(103,352)	(118,685)	(106,464)
INCOME BEFORE INCOME TAXES	375,397	306,226	389,430
Income Tax Expense	124,978	96,110	138,399
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	250,419	210,116	251,031
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax	(4,575)	-	124,632
NET INCOME	245,844	210,116	375,663
Preferred Stock Dividend Requirements including Other Expense	906	733	1,098
EARNINGS APPLICABLE TO COMMON STOCK	$ 244,938	$ 209,383	$ 374,565

The common stock of OPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 321,201	$ 462,483	$ 522,316	$ (72,886)	$ 1,233,114
Common Stock Dividends			(167,734)		(167,734)
Preferred Stock Dividends			(1,098)		(1,098)
Capital Stock Gains		1			1
TOTAL					1,064,283
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $342				635	635
Minimum Pension Liability, Net of Tax of $13,495				23,444	23,444
NET INCOME			375,663		375,663
TOTAL COMPREHENSIVE INCOME					399,742
DECEMBER 31, 2003	321,201	462,484	729,147	(48,807)	1,464,025
Common Stock Dividends			(174,114)		(174,114)
Preferred Stock Dividends			(733)		(733)
Capital Stock Gains		1			1
TOTAL					1,289,179
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $723				1,344	1,344
Minimum Pension Liability, Net of Tax of $14,432				(26,801)	(26,801)
NET INCOME			210,116		210,116
TOTAL COMPREHENSIVE INCOME					184,659
DECEMBER 31, 2004	321,201	462,485	764,416	(74,264)	1,473,838
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(732)		(732)
Other		4,152	(174)		3,978
TOTAL					1,447,084
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $262				(486)	(486)
Minimum Pension Liability, Net of Tax of $40,657				75,505	75,505
NET INCOME			245,844		245,844
TOTAL COMPREHENSIVE INCOME					320,863
DECEMBER 31, 2005	$ 321,201	$ 466,637	$ 979,354	$ 755	$ 1,767,947

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,240	$ 9,337
Advances to Affiliates	-	125,971
Accounts Receivable:		
Customers	125,404	98,951
Affiliated Companies	167,579	144,175
Accrued Unbilled Revenues	14,817	10,641
Miscellaneous	15,644	7,626
Allowance for Uncollectible Accounts	(1,517)	(93)
Total Accounts Receivable	321,927	261,300
Fuel	97,600	70,309
Materials and Supplies	60,937	55,569
Emission Allowances	39,251	95,303
Risk Management Assets	115,020	79,541
Accrued Tax Benefits	39,965	-
Prepayments and Other	27,439	15,877
TOTAL	703,379	713,207
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,278,553	4,127,284
Transmission	1,002,255	978,492
Distribution	1,258,518	1,202,550
Other	293,794	309,488
Construction Work in Progress	690,168	240,957
Total	7,523,288	6,858,771
Accumulated Depreciation and Amortization	2,738,899	2,633,203
TOTAL - NET	4,784,389	4,225,568
OTHER NONCURRENT ASSETS		
Regulatory Assets	398,007	428,374
Long-term Risk Management Assets	144,015	66,727
Deferred Charges and Other	300,880	159,389
TOTAL	842,902	654,490
TOTAL ASSETS	$ 6,330,670	$ 5,593,265

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 70,071	$ -
Accounts Payable:		
General	210,752	145,826
Affiliated Companies	147,470	116,615
Short-term Debt – Nonaffiliated	10,366	23,498
Long-term Debt Due Within One Year – Affiliated	200,000	-
Long-term Debt Due Within One Year – Nonaffiliated	12,354	12,354
Cumulative Preferred Stock Subject to Mandatory Redemption	-	5,000
Risk Management Liabilities	108,797	70,311
Customer Deposits	51,209	22,620
Accrued Taxes	158,774	233,026
Accrued Interest	36,298	39,254
Other	111,480	81,479
TOTAL	1,117,571	749,983
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,787,316	1,598,706
Long-term Debt – Affiliated	200,000	400,000
Long-term Risk Management Liabilities	119,247	46,261
Deferred Income Taxes	987,386	943,465
Regulatory Liabilities and Deferred Investment Tax Credits	168,492	115,414
Deferred Credits and Other	154,770	234,874
TOTAL	3,417,211	3,338,720
TOTAL LIABILITIES	4,534,782	4,088,703
Minority Interest	11,302	14,083
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,639	16,641
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value Per Share:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	466,637	462,485
Retained Earnings	979,354	764,416
Accumulated Other Comprehensive Income (Loss)	755	(74,264)
TOTAL	1,767,947	1,473,838
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,330,670	$ 5,593,265

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 245,844	$ 210,116	$ 375,663
Adjustments for Noncash Items:			
Depreciation and Amortization	302,495	286,300	257,417
Deferred Income Taxes	59,593	23,329	24,482
Cumulative Effect of Accounting Changes, Net of Tax	4,575	-	(124,632)
Carrying Costs Income	(48,510)	(735)	(592)
Mark-to-Market of Risk Management Contracts	(2,372)	1,171	60,064
Pension Contributions to Qualified Plan Trusts	(132,496)	(764)	(6,989)
Change in Other Noncurrent Assets	5,806	(10,398)	(25,319)
Change in Other Noncurrent Liabilities	(15,180)	(2,563)	(22,027)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(60,627)	(22,640)	(3,966)
Fuel, Materials and Supplies	(32,659)	1,329	7,472
Accounts Payable	56,403	31,023	(163,191)
Accrued Taxes, Net	(114,217)	100,233	21,015
Customer Deposits	28,589	5,312	4,339
Other Current Assets	44,516	(71,141)	(13,209)
Other Current Liabilities	27,045	(4,717)	1,462
Net Cash Flows From Operating Activities	368,805	545,855	391,989
INVESTING ACTIVITIES			
Construction Expenditures	(710,536)	(320,215)	(259,010)
Change in Other Cash Deposits, Net	(29)	50,956	(50,956)
Change in Advances to Affiliates, Net	125,971	(58,053)	(67,918)
Proceeds from Sale of Assets	13,409	2,920	12,671
Other	1	-	6
Net Cash Flows Used For Investing Activities	(571,184)	(324,392)	(365,207)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	545,746	-	988,914
Issuance of Long-term Debt – Affiliated	-	400,000	-
Change in Short-term Debt, Net – Nonaffiliated	(13,132)	(2,443)	(671)
Change in Short-term Debt, Net – Affiliated	-	-	(275,000)
Change in Advances from Affiliates, Net	70,071	-	(129,979)
Retirement of Long-term Debt – Nonaffiliated	(365,354)	(431,854)	(128,378)
Retirement of Long-term Debt – Affiliated	-	-	(300,000)
Retirement of Cumulative Preferred Stock	(5,000)	(2,254)	(1,603)
Principal Payments for Capital Lease Obligations	(7,317)	(8,022)	(9,224)
Dividends Paid on Common Stock	(30,000)	(174,114)	(167,734)
Dividends Paid on Cumulative Preferred Stock	(732)	(733)	(1,098)
Net Cash Flows From (Used For) Financing Activities	194,282	(219,420)	(24,773)
Net Increase (Decrease) in Cash and Cash Equivalents	(8,097)	2,043	2,009
Cash and Cash Equivalents at Beginning of Period	9,337	7,294	5,285
Cash and Cash Equivalents at End of Period	$ 1,240	$ 9,337	$ 7,294

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $102,656,000, $119,562,000 and $77,170,000 and for income taxes was $198,078,000, $(21,600,000) and $98,923,000 in 2005, 2004 and 2003, respectively. Noncash acquisitions under capital leases were $9,218,000, $14,727,000 and $1,556,000 in 2005, 2004 and 2003, respectively. Noncash activity in 2003 included an increase in assets and liabilities of $469.6 million resulting from the consolidation of JMG (see "Gavin Scrubber Financing Arrangement" section of Note 15). Noncash construction expenditures included in Accounts Payable of $74,848,000, $35,470,000 and $12,178,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003; and FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004. As discussed in Note 15 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,304,078	$ 1,047,820	$ 1,107,931	$ 793,282	$ 957,173
Operating Income	$ 118,016	$ 82,806	$ 135,840	$ 101,911	$ 129,934
Net Income	$ 57,893	$ 37,542	$ 53,891	$ 41,060	$ 57,759
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 2,994,995	$ 2,875,839	$ 2,818,514	$ 2,771,161	$ 2,699,573
Accumulated Depreciation and Amortization	1,175,858	1,117,535	1,069,417	1,037,222	989,426
Net Property, Plant and Equipment	$ 1,819,137	$ 1,758,304	$ 1,749,097	$ 1,733,939	$ 1,710,147
Total Assets	$ 2,355,464	$ 2,066,825	$ 1,976,477	$ 1,987,077	$ 1,946,475
Common Shareholder's Equity	$ 548,597	$ 529,256	$ 483,008	$ 399,247	$ 480,240
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 5,262	$ 5,262	$ 5,267	$ 5,267	$ 5,267
Trust Preferred Securities (a)	$ -	$ -	$ -	$ 75,000	$ 75,000
Long-term Debt (b)	$ 571,071	$ 546,092	$ 574,298	$ 545,437	$ 451,129
Obligations Under Capital Leases (b)	$ 2,534	$ 1,284	$ 1,010	$ -	$ -

(a) See "Trust Preferred Securities" section of Note 16.
(b) Including portion due within one year.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 514,000 retail customers in eastern and southwestern Oklahoma. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Members of the CSW Operating Agreement are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are generally shared among the members based upon the relative magnitude of the energy each member provides to make such sales. We share these margins with our customers.

On behalf of the AEP East companies and AEP West companies, AEPSC filed with the FERC to remove TCC and TNC from the CSW Operating Agreement and the SIA. Under the Texas Restructuring Legislation, TCC and TNC are completing the final stage of exiting the generation business and have already ceased serving retail load. Upon approval by the FERC, TCC and TNC will no longer be involved in the coordinated planning and operation of power supply facilities as contemplated by both the CSW Operating Agreement and the SIA. Therefore, once approved by the FERC, TCC and TNC will no longer share trading and marketing margins, which, due to restructuring, affected their results of operations and cash flows. Conversely, our proportionate share of trading and marketing margins will increase, although the level of margins depends upon future market conditions. We share these margins with our customers.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to both SWEPCo's and our benefit. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to December 31, 2005
Net Income
(in millions)

Year Ended December 31, 2004		$ 38
Changes in Gross Margin:		
Retail and Off-system Sales Margins	25	
Transmission Revenues	6	
Other Revenue	2	
Total Change in Gross Margin		33
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(5)	
Depreciation and Amortization	3	
Taxes Other Than Income Taxes	4	
Interest Expense	4	
Other Income	4	
Total Change in Operating Expenses and Other		10
Income Tax Expense		(23)
Year Ended December 31, 2005		$ 58

Net Income increased $20 million to $58 million in 2005. The key drivers of the increase were a $33 million increase in Gross Margin and a $10 million decrease in Operating Expenses and Other, partially offset by a $23 million increase in Income Tax Expense.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $25 million primarily due to higher retail sales volumes resulting from a 12% increase in degree days and an increased number of customers.
- Transmission Revenues increased $6 million primarily due to higher rates within SPP.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased $5 million, primarily due to a $10 million increase in power plant operation and maintenance expenses. The increase was partially offset by a $3 million decrease in transmission-related expenses due to adjustments in 2004 for affiliated OATT and ancillary services. This adjustment was a result of revised ERCOT data for the years 2001 through 2003. In addition, distribution expenses decreased $2 million primarily due to 2004 storm-related expenses and a one-time labor-related settlement, partially offset by higher overhead line expense in 2005.
- Depreciation and Amortization decreased $3 million primarily due to a change in depreciation rates effective June 2005, resulting from the settlement of our 2005 rate review proceedings (See "PSO Rate Review" Section of Note 4).
- Taxes Other Than Income Taxes decreased $4 million primarily due to an adjustment for property-related taxes recorded in 2005.
- Interest Expense decreased $4 million primarily due to the 2004 replacement of higher rate first mortgage bonds and trust preferred securities with lower rate senior unsecured notes and affiliated notes.
- Other Income increased $4 million. The key drivers were an increase in retail interest on deferred fuel and a $2 million favorable Internal Revenue Service audit settlement.

Income Taxes

The increase in income tax expense of $23 million is primarily due to an increase in pretax book income and adjustments to tax reserve accounts.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa1	BBB	A-

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 75.9	$ -	$ -	$ -	$ 75.9
Interest on Fixed Rate Portion of Long-term Debt (b)	26.7	51.8	48.3	273.0	399.8
Fixed Rate Portion of Long-term Debt (c)	50.0	-	200.0	287.7	537.7
Variable Rate Portion of Long-term Debt (d)	-	-	-	33.7	33.7
Capital Lease Obligations (e)	0.9	1.2	0.7	0.1	2.9
Noncancelable Operating Leases (e)	6.2	9.2	6.5	6.4	28.3
Fuel Purchase Contracts (f)	277.4	185.1	136.8	259.9	859.2
Energy and Capacity Purchase Contracts (g)	78.5	150.7	124.4	219.9	573.5
Construction Contracts for Capital Assets (h)	55.1	-	-	-	55.1
Total	$ 570.7	$ 398.0	$ 516.7	$ 1,080.7	$ 2,566.1

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had an interest rate of 3.15% at December 31, 2005.
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

Net Cash Flows from Operating Activities were adversely and significantly impacted by our under-recovery of fuel costs during 2005. However, we implemented new factors in December 2005 that are estimated to increase 2006 revenues by approximately $349 million, thereby reducing our under-recovery of fuel costs. This fuel factor adjustment will increase cash flows without impacting results of operations.

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Balance Sheet
As of December 31, 2005
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 39,924	$ 459	$ 40,383
Noncurrent Assets	33,566	-	33,566
Total MTM Derivative Contract Assets	73,490	459	73,949
Current Liabilities	(36,858)	(1,385)	(38,243)
Noncurrent Liabilities	(22,418)	(164)	(22,582)
Total MTM Derivative Contract Liabilities	(59,276)	(1,549)	(60,825)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 14,214	$ (1,090)	$ 13,124

MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 14,771
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	293
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(88)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	(469)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(293)
Total MTM Risk Management Contract Net Assets	14,214
Net Cash Flow Hedge Contracts	(1,090)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 13,124

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 2,489	$ 1,638	$ 474	$ -	$ -	$ -	$ 4,601
Prices Provided by Other External Sources - OTC Broker Quotes (a)	5,973	4,178	4,460	2,173	-	-	16,784
Prices Based on Models and Other Valuation Methods (b)	(5,395)	(3,075)	(1,733)	348	1,694	990	(7,171)
Total	$ 3,067	$ 2,741	$ 3,201	$ 2,521	$ 1,694	$ 990	$ 14,214

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 1,000	$ (600)	$ 400
Changes in Fair Value	(1,217)	49	(1,168)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(412)	68	(344)
Ending Balance in AOCI December 31, 2005	$ (629)	$ (483)	$ (1,112)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $632 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$311	$517	$246	$89	$238	$778	$335	$115

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $34 million and $35 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,261,424	$ 1,035,306	$ 1,077,422
Sales to AEP Affiliates	39,678	10,690	23,130
Other	2,976	1,824	7,379
TOTAL	1,304,078	1,047,820	1,107,931
EXPENSES			
Fuel and Other Consumables for Electric Generation	619,657	434,390	526,405
Fuel from Affiliates for Electric Generation	-	30	158
Purchased Electricity for Resale	116,345	79,325	35,685
Purchased Electricity from AEP Affiliates	105,361	104,001	109,639
Other Operation	156,451	155,441	128,386
Maintenance	67,077	63,529	53,076
Depreciation and Amortization	86,762	89,711	86,455
Taxes Other Than Income Taxes	34,409	38,587	32,287
TOTAL	1,186,062	965,014	972,091
OPERATING INCOME	118,016	82,806	135,840
Other Income (Expense):			
Interest Income	3,591	166	341
Allowance for Equity Funds Used During Construction	865	336	331
Interest Expense	(34,094)	(37,957)	(44,784)
INCOME BEFORE INCOME TAXES	88,378	45,351	91,728
Income Tax Expense	30,485	7,809	37,837
NET INCOME	57,893	37,542	53,891
Preferred Stock Dividend Requirements, Including Gain on Reacquired Preferred Stock	213	211	213
EARNINGS APPLICABLE TO COMMON STOCK	$ 57,680	$ 37,331	$ 53,678

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 157,230	$ 180,016	$ 116,474	$ (54,473)	$ 399,247
Capital Contribution from Parent Company		50,000			50,000
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(213)		(213)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent Company			(548)		(548)
TOTAL					418,486
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $106				198	198
Minimum Pension Liability, Net of Tax of $5,649				10,433	10,433
NET INCOME			53,891		53,891
TOTAL COMPREHENSIVE INCOME					64,522
DECEMBER 31, 2003	157,230	230,016	139,604	(43,842)	483,008
Gain on Reacquired Preferred Stock			2		2
Common Stock Dividends			(35,000)		(35,000)
Preferred Stock Dividends			(213)		(213)
TOTAL					447,797
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $131				244	244
Minimum Pension Liability, Net of Tax of $23,516				43,673	43,673
NET INCOME			37,542		37,542
TOTAL COMPREHENSIVE INCOME					81,459
DECEMBER 31, 2004	157,230	230,016	141,935	75	529,256
Common Stock Dividends			(37,000)		(37,000)
Preferred Stock Dividends			(213)		(213)
TOTAL					492,043
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $814				(1,512)	(1,512)
Minimum Pension Liability, Net of Tax of $93				173	173
NET INCOME			57,893		57,893
TOTAL COMPREHENSIVE INCOME					56,554
DECEMBER 31, 2005	$ 157,230	$ 230,016	$ 162,615	$ (1,264)	$ 548,597

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,520	$ 279
Accounts Receivable:		
Customers	37,740	32,009
Affiliated Companies	73,321	46,399
Miscellaneous	10,501	9,066
Allowance for Uncollectible Accounts	(240)	(76)
Total Accounts Receivable	121,322	87,398
Fuel	16,431	14,268
Materials and Supplies	38,545	35,485
Risk Management Assets	40,383	21,388
Regulatory Asset for Under-Recovered Fuel Costs	108,732	366
Accrued Tax Benefits	11,972	-
Prepayments and Other	14,287	6,200
TOTAL	353,192	165,384
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,072,928	1,072,022
Transmission	479,272	468,735
Distribution	1,140,535	1,089,187
Other	211,805	204,867
Construction Work in Progress	90,455	41,028
Total	2,994,995	2,875,839
Accumulated Depreciation and Amortization	1,175,858	1,117,535
TOTAL - NET	1,819,137	1,758,304
OTHER NONCURRENT ASSETS		
Regulatory Assets	50,723	31,951
Long-term Risk Management Assets	33,566	14,477
Employee Benefits and Pension Assets	82,559	82,423
Deferred Charges and Other	16,287	14,286
TOTAL	183,135	143,137
TOTAL ASSETS	$ 2,355,464	$ 2,066,825

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 75,883	$ 55,002
Accounts Payable:		
General	130,627	69,449
Affiliated Companies	89,786	58,632
Long-term Debt Due Within One Year – Nonaffiliated	-	50,000
Long-term Debt Due Within One Year – Affiliated	50,000	-
Risk Management Liabilities	38,243	13,705
Customer Deposits	53,844	33,757
Accrued Taxes	22,420	18,835
Other	51,548	35,037
TOTAL	512,351	334,417
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	521,071	446,092
Long-term Debt – Affiliated	-	50,000
Long-term Risk Management Liabilities	22,582	7,455
Deferred Income Taxes	436,382	384,090
Regulatory Liabilities and Deferred Investment Tax Credits	284,640	290,557
Deferred Credits and Other	24,579	19,696
TOTAL	1,289,254	1,197,890
TOTAL LIABILITIES	1,801,605	1,532,307
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $15 Par Value Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	230,016	230,016
Retained Earnings	162,615	141,935
Accumulated Other Comprehensive Income (Loss)	(1,264)	75
TOTAL	548,597	529,256
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,355,464	$ 2,066,825

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 57,893	$ 37,542	$ 53,891
Adjustments for Noncash Items:			
Depreciation and Amortization	86,762	89,711	86,455
Deferred Income Taxes	46,342	22,034	(14,641)
Mark-to-Market of Risk Management Contracts	557	(714)	(10,511)
Pension Contributions to Qualified Plan Trusts	(286)	(48,701)	(88)
Change in Other Noncurrent Assets	(30,602)	(24,711)	(10,619)
Change in Other Noncurrent Liabilities	8,603	24,848	15,234
Changes in Components of Working Capital:			
Accounts Receivable, Net	(33,924)	(37,826)	(818)
Fuel, Materials and Supplies	(5,223)	6,731	906
Accounts Payable	86,314	23,535	(36,887)
Accrued Taxes, Net	(8,387)	(8,322)	20,303
Customer Deposits	20,087	7,210	4,758
Over/Under Fuel Recovery	(108,366)	23,804	52,300
Other Current Assets	(8,081)	755	(3,625)
Other Current Liabilities	16,511	(4,353)	7,456
Net Cash Flows From Operating Activities	128,200	111,543	164,114
INVESTING ACTIVITIES			
Construction Expenditures	(134,358)	(82,618)	(84,598)
Change in Other Cash Deposits, Net	(6)	10,258	(3,289)
Proceeds from Sales of Assets	-	458	2,862
Net Cash Flows Used For Investing Activities	(134,364)	(71,902)	(85,025)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	-	-	50,000
Issuance of Long-term Debt – Nonaffiliated	74,405	82,255	148,734
Issuance of Long-term Debt – Affiliated	-	50,000	-
Change in Advances from Affiliates, Net	20,881	22,138	(53,241)
Retirement of Long-term Debt – Nonaffiliated	(50,000)	(162,020)	(200,000)
Retirement of Preferred Stock	-	(2)	-
Principal Payments for Capital Lease Obligations	(668)	(520)	(174)
Dividends Paid on Common Stock	(37,000)	(35,000)	(30,000)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows From (Used For) Financing Activities	7,405	(43,362)	(84,894)
Net Increase (Decrease) in Cash and Cash Equivalents	1,241	(3,721)	(5,805)
Cash and Cash Equivalents at Beginning of Period	279	4,000	9,805
Cash and Cash Equivalents at End of Period	$ 1,520	$ 279	$ 4,000

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $29,607,000, $32,961,000 and $44,703,000 and for income taxes was $(5,244,000), $2,387,000 and $36,470,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $1,918,000, $796,000 and $1,248,000, in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $8,495,000, $2,477,000 and $3,106,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. There was a noncash distribution of $548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2005 and 2004, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 11 and 16 to the financial statements, respectively, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004, and FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,405,379	$ 1,091,072	$ 1,148,812	$ 1,085,100	$ 1,101,663
Operating Income	$ 160,537	$ 179,239	$ 203,778	$ 174,711	$ 185,431
Income Before Cumulative Effect of Accounting Changes	$ 75,190	$ 89,457	$ 89,624	$ 82,992	$ 89,367
Cumulative Effect of Accounting Changes, Net of Tax	(1,252)	-	8,517	-	-
Net Income	$ 73,938	$ 89,457	$ 98,141	$ 82,992	$ 89,367
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 4,006,639	$ 3,892,508	$ 3,804,600	$ 3,600,407	$ 3,464,997
Accumulated Depreciation and Amortization	1,776,216	1,710,850	1,619,178	1,477,904	1,342,003
Net Property, Plant and Equipment	$ 2,230,423	$ 2,181,658	$ 2,185,422	$ 2,122,503	$ 2,122,994
Total Assets	$ 2,797,347	$ 2,646,849	$ 2,581,727	$ 2,429,366	$ 2,510,746
Common Shareholder's Equity	$ 782,378	$ 768,618	$ 696,660	$ 661,769	$ 689,578
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 4,700	$ 4,700	$ 4,700	$ 4,701	$ 4,701
Trust Preferred Securities (a)	$ -	$ -	$ -	$ 110,000	$ 110,000
Long-term Debt (b)	$ 746,035	$ 805,369	$ 884,308	$ 693,448	$ 645,283
Obligations Under Capital Leases (b)	$ 42,545	$ 34,546	$ 21,542	$ -	$ -

(a) See "Trust Preferred Securities" section of Note 16.
(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 450,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. We consolidate Southwest Arkansas Utilities Corporation and Dolet Hills Lignite Company, LLC, our wholly-owned subsidiaries. We also consolidate Sabine Mining Company, a variable interest entity. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and electric cooperatives.

Members of the CSW Operating Agreement are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are generally shared among the members based upon the relative magnitude of the energy each member provides to make such sales. We share these margins with our customers.

On behalf of the AEP East companies and AEP West companies, AEPSC filed with the FERC to remove TCC and TNC from the CSW Operating Agreement and the SIA. Under the Texas Restructuring Legislation, TCC and TNC are completing the final stage of exiting the generation business and have already ceased serving retail load. Upon approval by the FERC, TCC and TNC will no longer be involved in the coordinated planning and operation of power supply facilities as contemplated by both the CSW Operating Agreement and the SIA. Therefore, once approved by the FERC, TCC and TNC will no longer share trading and marketing margins, which, due to restructuring, affected their results of operations and cash flows. Conversely, our proportionate share of trading and marketing margins will increase, although the level of margins depends upon future market conditions. We share these margins with our customers.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool agreements and the SIA. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to both PSO's and our benefit. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

We are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 89
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	23	
Transmission Revenues	4	
Other Revenues	8	
Total Change in Gross Margin		35
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(49)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(3)	
Interest Expense	4	
Other Income	1	
Total Change in Operating Expenses and Other		(49)
Year Ended December 31, 2005		$ 75

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Changes decreased $14 million to $75 million in 2005. The key drivers of the decrease were a $49 million increase in Other Operation and Maintenance expense partially offset by a $35 million increase in Gross Margin.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $23 million primarily due to higher wholesale volumes and higher retail sales volumes resulting from a 10% increase in degree days. This was offset by the 2005 absence of a $9 million refund received in 2004 for prior year purchased capacity amounts. Capacity-related transactions are excluded from fuel adjustment clauses. Therefore, these transactions impact gross margin.
- Transmission Revenues increased $4 million primarily due to higher rates within SPP.
- Other Revenues increased $8 million primarily due to a $4 million increase in pole attachment billings and other miscellaneous revenues.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $49 million. This was primarily due to a $27 million increase in power plant operation and maintenance during extended planned power plant outages. Distribution expense increased $14 million, comprised primarily of a $10 million increase in tree trimming and right-of-way clearing and $3 million of storm damage related to hurricanes. Transmission expenses decreased $2 million. This was due to the absence in 2005 of a 2004 adjustment related to revised ERCOT data for the years 2001 through 2003, offset in part by higher SPP charges. Customer-related expense increased $6 million due to increased collection activities as well as increased factoring expense resulting from higher interest rates and higher volumes of receivables factored.
- Taxes Other Than Income Taxes increased $3 million primarily due to higher gross receipts and payroll-related taxes.
- Interest Expense decreased $4 million primarily due to decreased long-term debt and decreased interest expense related to fuel recovery.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$	90
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	13		
Transmission Revenues	2		
Other Revenues	(3)		
Total Change in Gross Margin			12
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(18)		
Depreciation and Amortization	(8)		
Taxes Other Than Income Taxes	(11)		
Interest Expense	10		
Total Change in Operating Expenses and Other			(27)
Income Tax Expense			16
Minority Interest Expense			(2)
Year Ended December 31, 2004		$	89

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Changes decreased less than $1 million in 2004. The key drivers were a $12 million increase in Gross Margin and a $16 million decrease in Income Tax Expense, partially offset by a $27 million increase in Operating Expenses and Other.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $13 million primarily due to a $9 million refund received in 2004 for purchased capacity amounts. Capacity-related transactions are excluded from fuel adjustment clauses. Therefore, these transactions impact gross margin. In addition, provisions for rate refund decreased $2 million due to 2003 wholesale refunds.
- Transmission Revenues increased $2 million due to higher affiliated transmission services.
- Other Revenues decreased $3 million primarily due to decreased rent from electric property.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $18 million. Transmission-related expenses increased $14 million primarily due to a 2004 adjustment related to revised ERCOT data for the years 2001 through 2003. In addition, maintenance expense increased $4 million as a result of scheduled power plant maintenance and increased overhead line maintenance.
- Depreciation and Amortization increased $8 million primarily due to the recovery and amortization of a regulatory asset for fuel-related costs in Arkansas in 2003. Depreciation also increased due to additions of depreciable plant assets.
- Taxes Other Than Income Taxes increased $11 million primarily due to an $8 million increase in franchise taxes resulting from a 2003 true-up of prior years in addition to increased property-related taxes.
- Interest Expense decreased $10 million as a result of refinancing higher interest rate debt with lower interest rate debt.

Income Taxes

The decrease in Income Tax Expense of $16 million is primarily due to a decrease in pretax book income, state income taxes and adjustments to prior year accruals.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

Cash Flow

Cash flows for the years ended December 31, 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 3,715	$ 6,215	$ 349
Cash Flows From (Used For):			
Operating Activities	208,153	209,107	248,503
Investing Activities	(115,073)	(65,525)	(180,089)
Financing Activities	(93,746)	(146,082)	(62,548)
Net Increase (Decrease) in Cash and Cash Equivalents	(666)	(2,500)	5,866
Cash and Cash Equivalents at End of Period	$ 3,049	$ 3,715	$ 6,215

Operating Activities

Our Net Cash Flows From Operating Activities were $208 million in 2005. We produced Net Income of $74 million during the period and noncash expense items of $132 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The most significant are Accounts Receivable, Accounts Payable, and Customer Deposits, all of which were driven by higher fuel-related costs. Our cash flow related to Over/Under Fuel Recovery was also adversely affected by rising fuel costs, but is expected to improve with the new fuel surcharges placed into effect in December 2005 in our Arkansas service territory and in January 2006 in our Texas service territory. The surcharges are expected to recover approximately $18 million of the fuel under-recovery in Arkansas over an 18-month period and $46 million of the fuel under-recovery in Texas over a 12-month period. Accounts Receivable increased $28 million due to higher affiliated energy sales. Accounts Payable increased $50 million primarily due to higher energy and fuel-related purchases as well as increased vendor-related payables.

Our Net Cash Flows From Operating Activities were $209 million in 2004. We produced Net Income of $89 million during the period and noncash expense items of $129 million for Depreciation and Amortization. Pension Contributions to Qualified Plan Trusts were $46 million. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items, the most significant being Accrued Taxes, Fuel, Materials and Supplies, and Accounts Receivable. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payments were made in 2005. The decrease in Fuel and Materials and Supplies was primarily due to lower fuel purchases. Accounts Receivable increased due to higher affiliated energy sales.

Our Net Cash Flows From Operating Activities were $249 million in 2003. We produced Net Income of $98 million during the period, noncash expense items of $121 million for Depreciation and Amortization and $9 million for Cumulative Effect of Account Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items, the most significant being Accounts Receivable and Accounts Payable. Accounts Receivable decreased primarily due to an adjustment to the interchange cost construction system. The decrease in Accounts Payable was related to lower fuel purchases.

Investing Activities

Cash Flows Used For Investing Activities during 2005, 2004 and 2003 were $115 million, $66 million and $180 million, respectively. They were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability and Advances to Affiliates.

Financing Activities

Cash Flows Used For Financing Activities were $94 million during 2005. During the year, we issued $150 million of Senior Unsecured Notes. Proceeds were used to fund the July 2005 maturity of $200 million of Senior Unsecured Notes. In addition, we borrowed $28 million from the Utility Money Pool. Common Stock Dividends were $55 million.

Cash Flows Used For Financing Activities were $146 million during 2004. During the first and second quarter, we retired $80 million and $40 million of First Mortgage Bonds, respectively. Three Installment Purchase Contracts were retired in the second quarter totaling $41 million. During the third quarter of 2004, we issued a Note Payable to AEP for $50 million. Common Stock Dividends were $60 million.

Cash Flows Used For Financing Activities were $63 million during 2003. During the first quarter of 2003, we retired $55 million of First Mortgage Bonds at maturity. In April 2003, we issued $100 million of Senior Unsecured Notes. In May 2003, one of our mining subsidiaries issued $44 million of notes payable. During the fourth quarter of 2003, we had an early redemption of $45 million of First Mortgage Bonds. Common Stock Dividends were $73 million.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 28.2	$ -	$ -	$ -	$ 28.2
Interest on Fixed Rate Portion of Long-term Debt (b)	35.0	62.0	42.1	100.4	239.5
Fixed Rate Portion of Long-term Debt (c)	12.8	103.7	58.8	466.6	641.9
Variable Rate Portion of Long-term Debt (d)	4.4	4.5	-	94.6	103.5
Capital Lease Obligations (e)	8.5	16.6	11.7	22.8	59.6
Noncancelable Operating Leases (e)	6.2	10.8	7.2	6.4	30.6
Fuel Purchase Contracts (f)	267.0	284.8	284.9	284.9	1,121.6
Energy and Capacity Purchase Contracts (g)	115.1	187.0	153.8	324.1	780.0
Construction Contracts for Capital Assets (h)	39.9	-	-	-	39.9
Total	$ 517.1	$ 669.4	$ 558.5	$ 1,299.8	$ 3,044.8

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had interest rates of 3.10% and 5.31% at December 31, 2005
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2005 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a)	$ 4	$ -	$ -	$ -	$ 4
Guarantees of the Performance of Outside Parties (b)	8	-	25	105	138
Total	$ 12	$ -	$ 25	$ 105	$ 142

(a) We have issued standby letters of credit to third parties. These letters of credit cover insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $4 million maturing in March 2006. There is no recourse to third parties in the event these letters of credit are drawn. See "Letters of Credit" section of Note 8.
(b) See "SWEPCo" section of Note 8.

Other

On July 1, 2003, we consolidated Sabine due to the application of FIN 46. Upon consolidation, we recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, we currently record all expenses (depreciation, interest and other operation expense) of Sabine and eliminate Sabine's revenues against our fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.
See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet As of December 31, 2005 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 46,783	$ 536	$ 47,319
Noncurrent Assets	39,796	-	39,796
Total MTM Derivative Contract Assets	86,579	536	87,115
Current Liabilities	(43,409)	(1,689)	(45,098)
Noncurrent Liabilities	(26,783)	(300)	(27,083)
Total MTM Derivative Contract Liabilities	(70,192)	(1,989)	(72,181)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 16,387	$ (1,453)	$ 14,934

MTM Risk Management Contract Net Assets Year Ended December 31, 2005 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 17,527
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(4,439)
Fair Value of New Contracts at Inception When Entered During the Period (a)	158
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(561)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	3,555
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	147
Total MTM Risk Management Contract Net Assets	16,387
Net Cash Flow Hedge Contracts	(1,453)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 14,934

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2005
(in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 3,419	$ 1,914	$ 554	$ -	$ -	$ -	$ 5,887
Prices Provided by Other External Sources - OTC Broker Quotes (a)	6,456	5,167	5,250	2,540	-	-	19,413
Prices Based on Models and Other Valuation Methods (b)	(6,501)	(3,746)	(2,209)	406	1,980	1,157	(8,913)
Total	$ 3,374	$ 3,335	$ 3,595	$ 2,946	$ 1,980	$ 1,157	$ 16,387

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 1,188	$ (2,008)	$ (820)
Changes in Fair Value	(1,438)	(3,379)	(4,817)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(486)	271	(215)
Ending Balance in AOCI December 31, 2005	$ (736)	$ (5,116)	$ (5,852)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,150 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$363	$604	$287	$104	$283	$923	$398	$136

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $31 million and $31 million at December 31, 2005 and 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,338,882	$ 1,018,209	$ 1,078,414
Sales to AEP Affiliates	65,408	71,190	68,854
Other	1,089	1,673	1,544
TOTAL	1,405,379	1,091,072	1,148,812
EXPENSES			
Fuel and Other Consumables for Electric Generation	527,525	388,380	440,080
Purchased Electricity for Resale	133,403	35,521	34,850
Purchased Electricity from AEP Affiliates	70,911	29,054	47,914
Other Operation	213,629	191,898	177,510
Maintenance	101,049	74,091	70,443
Depreciation and Amortization	131,620	129,329	121,072
Taxes Other Than Income Taxes	66,705	63,560	53,165
TOTAL	1,244,842	911,833	945,034
OPERATING INCOME	160,537	179,239	203,778
Other Income (Expense):			
Interest Income	1,499	1,658	1,426
Allowance for Equity Funds Used During Construction	2,394	781	1,100
Interest Expense	(50,089)	(54,261)	(64,105)
INCOME BEFORE INCOME TAXES, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	114,341	127,417	142,199
Income Tax Expense	34,922	34,727	51,072
Minority Interest Expense	4,226	3,230	1,500
Equity Earnings of Unconsolidated Subsidiaries	(3)	(3)	(3)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	75,190	89,457	89,624
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax	(1,252)	-	8,517
NET INCOME	73,938	89,457	98,141
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$ 73,709	$ 89,228	$ 97,912

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$ 135,660	$ 245,003	$ 334,789	$ (53,683)	$ 661,769
Common Stock Dividends			(72,794)		(72,794)
Preferred Stock Dividends			(229)		(229)
TOTAL					588,746
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $125				232	232
Minimum Pension Liability, Net of Tax of $5,138				9,541	9,541
NET INCOME			98,141		98,141
TOTAL COMPREHENSIVE INCOME					107,914
DECEMBER 31, 2003	135,660	245,003	359,907	(43,910)	696,660
Common Stock Dividends			(60,000)		(60,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					636,431
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $541				(1,004)	(1,004)
Minimum Pension Liability, Net of Tax of $23,550				43,734	43,734
NET INCOME			89,457		89,457
TOTAL COMPREHENSIVE INCOME					132,187
DECEMBER 31, 2004	135,660	245,003	389,135	(1,180)	768,618
Common Stock Dividends			(55,000)		(55,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					713,389
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,709				(5,032)	(5,032)
Minimum Pension Liability, Net of Tax of $44				83	83
NET INCOME			73,938		73,938
TOTAL COMPREHENSIVE INCOME					68,989
DECEMBER 31, 2005	$ 135,660	$ 245,003	$ 407,844	$ (6,129)	$ 782,378

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,049	$ 3,715
Advances to Affiliates	-	39,106
Accounts Receivable:		
Customers	47,515	39,425
Affiliated Companies	49,226	28,817
Miscellaneous	7,984	8,145
Allowance for Uncollectible Accounts	(548)	(45)
Total Accounts Receivable	104,177	76,342
Fuel	40,333	45,793
Materials and Supplies	34,821	36,051
Risk Management Assets	47,319	25,379
Regulatory Asset for Under-Recovered Fuel Costs	51,387	4,844
Prepayments and Other	34,010	29,011
TOTAL	315,096	260,241
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,660,392	1,663,161
Transmission	645,297	632,964
Distribution	1,153,026	1,114,480
Other	443,749	433,051
Construction Work in Progress	104,175	48,852
Total	4,006,639	3,892,508
Accumulated Depreciation and Amortization	1,776,216	1,710,850
TOTAL - NET	2,230,423	2,181,658
OTHER NONCURRENT ASSETS		
Regulatory Assets	81,776	55,115
Long-term Risk Management Assets	39,796	17,179
Employee Benefits and Pension Assets	83,330	81,144
Deferred Charges and Other	46,926	51,512
TOTAL	251,828	204,950
TOTAL ASSETS	$ 2,797,347	$ 2,646,849

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 28,210	$ -
Accounts Payable:		
General	71,138	40,384
Affiliated Companies	53,019	33,285
Long-term Debt Due Within One Year – Nonaffiliated	17,149	209,974
Risk Management Liabilities	45,098	18,607
Customer Deposits	50,848	30,550
Accrued Taxes	42,799	45,474
Other	82,699	59,666
TOTAL	390,960	437,940
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	678,886	545,395
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	27,083	9,128
Deferred Income Taxes	409,513	399,756
Regulatory Liabilities and Deferred Investment Tax Credits	320,066	309,918
Deferred Credits and Other	131,477	120,269
TOTAL	1,617,025	1,434,466
TOTAL LIABILITIES	2,007,985	1,872,406
Minority Interest	2,284	1,125
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $18 Par Value Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	245,003	245,003
Retained Earnings	407,844	389,135
Accumulated Other Comprehensive Income (Loss)	(6,129)	(1,180)
TOTAL	782,378	768,618
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,797,347	$ 2,646,849

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 73,938	$ 89,457	$ 98,141
Adjustments for Noncash Items:			
Depreciation and Amortization	131,620	129,329	121,072
Deferred Income Taxes	(4,942)	12,782	9,942
Cumulative Effect of Accounting Change, Net of Tax	1,252	-	(8,517)
Mark-to-Market of Risk Management Contracts	1,140	(921)	(12,403)
Pension Contributions to Qualified Plan Trusts	(3,450)	(45,688)	(805)
Change in Other Noncurrent Assets	(27,432)	(20,447)	21,492
Change in Other Noncurrent Liabilities	25,625	36,224	44,937
Changes in Components of Working Capital:			
Accounts Receivable, Net	(27,835)	(19,832)	28,991
Fuel, Materials and Supplies	6,690	15,824	4,177
Accounts Payable	45,742	(2,267)	(53,076)
Accrued Taxes, Net	(2,675)	16,783	8,446
Customer Deposits	20,298	6,290	4,150
Over/Under Fuel Recovery, Net	(53,410)	12,420	(21,577)
Other Current Assets	(8,307)	858	(6,331)
Other Current Liabilities	29,899	(21,705)	9,864
Net Cash Flows From Operating Activities	208,153	209,107	248,503
INVESTING ACTIVITIES			
Construction Expenditures	(157,595)	(98,954)	(120,099)
Change in Other Cash Deposits, Net	3,308	624	(3,789)
Change in Advances to Affiliates, Net	39,106	27,370	(66,476)
Proceeds from Sales of Assets	108	5,435	3,800
Other	-	-	6,475
Net Cash Flows Used For Investing Activities	(115,073)	(65,525)	(180,089)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	154,574	91,999	254,630
Issuance of Long-term Debt – Affiliated	-	50,000	-
Retirement of Long-term Debt – Nonaffiliated	(215,101)	(224,309)	(219,482)
Change in Advances from Affiliates, Net	28,210	-	(23,239)
Principal Payments for Capital Lease Obligations	(6,200)	(3,543)	(1,434)
Dividends Paid on Common Stock	(55,000)	(60,000)	(72,794)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows Used For Financing Activities	(93,746)	(146,082)	(62,548)
Net Increase (Decrease) in Cash and Cash Equivalents	(666)	(2,500)	5,866
Cash and Cash Equivalents at Beginning of Period	3,715	6,215	349
Cash and Cash Equivalents at End of Period	$ 3,049	$ 3,715	$ 6,215

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $43,673,000, $49,739,000 and $57,775,000 and for income taxes was $52,756,000, $11,326,000 and $33,616,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $9,629,000, $19,687,000 and $1,846,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $10,221,000, $5,475,000 and $2,086,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. Noncash activity in 2003 included an increase in assets and liabilities of $78 million resulting from the consolidation of Sabine Mining Company.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003. As discussed in Notes 8 and 16 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
7.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Company-wide Staffing and Budget Review	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Other Losses	APCo, CSPCo, I&M, KPCo, OPCo, TCC, TNC
11.	Benefit Plans	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
15.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Jointly-Owned Electric Utility Plant	CSPCo, PSO, SWEPCo, TCC, TNC
19.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of AEP's ten Registrant Subsidiaries is the generation, transmission and distribution of electric power. TCC and TNC are completing the final stage of exiting the generation business. AEGCo is an electricity generation business. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, Registrant Subsidiaries engage in wholesale electricity marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale power markets. Wholesale power markets are generally market-based and are not cost-based regulated unless a wholesaler negotiates and files a cost-based rate contract with the FERC or a generator/seller of wholesale power is determined by the FERC to have "market power." The FERC also regulates transmission service and rates particularly in states that have restructured and unbundled rates. The state commissions regulate all or portions of our retail operations and retail rates dependent on the status of customer choice in each state jurisdiction (see Note 6).

For the periods presented, AEP and its subsidiaries were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (PUHCA 1935). The Energy Policy Act of 2005 repealed PUHCA 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA 2005). With the repeal of PUHCA 1935, the SEC no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over holding company related activities has been transferred to the FERC. Regulations and required reporting under PUHCA 2005 are reduced compared to PUHCA 1935. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system.

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCo, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our consolidated financial statements. OPCo and SWEPCo also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see "SWEPCo" section of Note 8 and "Gavin Scrubber Financing Arrangement" section of Note 15). CSPCo, OPCo, PSO, SWEPCo, TCC and TNC also have generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the financial statements and the assets and liabilities are reflected in the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries' financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation", regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. The following Registrant Subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, and in Arkansas by SWEPCo in September 1999. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the nonregulated operations and investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003 and FIN 47 effective December 31, 2005 (see "Accounting for Asset Retirement Obligations" section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." Equity investments are required to be tested for impairment when it is determined that an other than temporary loss in value has occurred.

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Property, Plant and Equipment and Equity Investments are disclosed as regulated/nonregulated by functional class within the Depreciation, Depletion and Amortization section below.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries:

2005	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Production	$ 684,721	$ 379,641	3.5%	31	$ 472,575	$ 151,389	3.8%	40-50
Transmission	-	-	N.M.	N.M.	386,945	119,048	1.7%	25-75
Distribution	-	-	N.M.	N.M.	456,063	136,106	3.5%	11-75
CWIP	12,252	2,226	N.M.	N.M.	35,461	(1,126)	N.M.	N.M.
Other	2,251	1,058	16.0%	N.M.	57,776	20,241	9.4%	N.M.
Total	$ 699,224	$ 382,925			$ 1,408,820	$ 425,658		

	AEGCo Nonregulated				KPCo Nonregulated			
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Other	$ 118	$ -	N.M.	N.M.	$ 5,606	$ 159	2.0%	N.M.

2004	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Production	$ 681,254	$ 364,779	3.5%	31	$ 462,641	$ 139,677	3.8%	40-50
Transmission	-	-	N.M.	N.M.	385,667	113,199	1.7%	25-75
Distribution	-	-	N.M.	N.M.	438,766	127,858	3.5%	11-75
CWIP	7,729	1,341	N.M.	N.M.	16,544	(987)	N.M.	N.M.
Other	3,739	2,364	16.4%	N.M.	57,929	18,708	9.2%	N.M.
Total	$ 692,722	$ 368,484			$ 1,361,547	$ 398,455		

	AEGo Nonregulated				KPCo Nonregulated			
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Other	$ 119	$ -	N.M.	N.M.	$ 5,591	$ 153	2.0%	N.M.

2003	AEGCo Regulated		KPCo Regulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Production	3.5%	31	3.8%	40-50
Transmission	N.M.	N.M.	1.7%	25-75
Distribution	N.M.	N.M.	3.5%	11-75
Other	16.7%	N.M.	7.1 %	N.M.

TCC

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 817,351	$ 204,426	2.1%	40-71	$ -	$ -	N.M.	N.M.
Distribution	1,476,683	332,143	3.4%	15-62	-	-	N.M.	N.M.
CWIP	129,800	1,147	N.M.	N.M.	-	-	N.M.	N.M.
Other	229,893	97,196	6.5%	N.M.	3,468	1,166	2.9%	N.M.
Total	$ 2,653,727	$ 634,912			$ 3,468	$ 1,166		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 788,371	$ 234,914	2.3%	35-60	$ -	$ -	N.M.	N.M.
Distribution	1,433,380	405,412	3.4%	25-60	-	-	N.M.	N.M.
CWIP	50,612	8,256	N.M.	N.M.	-	-	N.M.	N.M.
Other	219,759	76,644	6.5%	N.M.	3,799	1,545	2.9%	N.M.
Total	$ 2,492,122	$ 725,226			$ 3,799	$ 1,545		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Production	2.5%	N.M.	2.3%	N.M.
Transmission	2.3%	35-60	2.1%	N.M.
Distribution	3.5%	25-60	N.M.	N.M.
Other	8.1%	N.M.	2.9%	N.M.

TNC

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 288,934	$ 117,963	2.6%	20-49
Transmission	289,029	98,630	3.0%	40-75	-	-	N.M.	N.M.
Distribution	492,878	144,465	3.2%	19-55	-	-	N.M.	N.M.
CWIP	42,929	(327)	N.M.	N.M.	3,495	-	N.M.	N.M.
Other	109,264	60,376	9.7%	N.M.	58,585	57,412	4.9%	N.M.
Total	$ 934,100	$ 303,144			$ 351,014	$ 175,375		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 287,212	$ 110,492	2.6%	20-49
Transmission	281,359	97,389	3.0%	40-75	-	-	N.M.	N.M.
Distribution	474,961	138,925	3.2%	19-55	-	-	N.M.	N.M.
CWIP	20,724	(2,768)	N.M.	N.M.	2,897	-	N.M.	N.M.
Other	115,174	61,895	8.4%	N.M.	123,244	121,837	4.9%	N.M.
Total	$ 892,218	$ 295,441			$ 413,353	$ 232,329		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Production	N.M.	N.M.	2.6 %	20-49
Transmission	3.1%	40-75	N.M.	N.M.
Distribution	3.3%	19-55	N.M.	N.M.
Other	10.2%	N.M.	4.9 %	N.M.

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,140,438	$ 515,967	2.9%	40-120	$ 1,657,719	$ 748,739	2.9%	40-120
Transmission	1,266,855	481,978	2.2%	35-65	-	-	N.M.	N.M.
Distribution	2,141,153	655,856	3.2%	10-60	-	-	N.M.	N.M.
CWIP	481,579	(4,844)	N.M.	N.M.	166,059	(5,210)	N.M.	N.M.
Other	289,924	119,178	9.3%	N.M.	33,234	13,191	3.2%	N.M.
Total	$ 5,319,949	$ 1,768,135			$ 1,857,012	$ 756,720		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,019,851	$ 500,928	2.8%	40-120	$ 1,482,422	$ 728,148	2.8%	40-120
Transmission	1,255,390	458,247	2.2%	35-65	-	-	N.M.	N.M.
Distribution	2,070,377	626,406	3.3%	10-60	-	-	N.M.	N.M.
CWIP	273,987	(29)	N.M.	N.M.	125,129	(2,610)	N.M.	N.M.
Other	302,474	132,130	9.4%	N.M.	33,577	13,197	3.2%	N.M.
Total	$ 4,922,079	$ 1,717,682			$ 1,641,128	$ 738,735		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.2%	40-120	3.2%	40-120
Transmission	2.2%	35-65	N.M.	N.M.
Distribution	3.3%	10-60	N.M.	N.M.
Other	9.3%	N.M.	3.2%	N.M.

CSPCo

2005

Functional Class of Property	Regulated: Property, Plant and Equipment (in thousands)	Regulated: Accumulated Depreciation (in thousands)	Regulated: Annual Composite Depreciation Rate	Regulated: Depreciable Life Ranges (in years)	Nonregulated: Property, Plant and Equipment (in thousands)	Nonregulated: Accumulated Depreciation (in thousands)	Nonregulated: Annual Composite Depreciation Rate	Nonregulated: Depreciable Life Ranges (in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,874,652	$ 759,789	3.1%	40-59
Transmission	457,937	192,282	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,380,722	475,669	3.6%	12-56	-	-	N.M.	N.M.
CWIP	69,800	(3,781)	N.M.	N.M.	59,446	63	N.M.	N.M.
Other	161,205	73,505	10.2%	N.M.	22,891	3,331	N.M.	N.M.
Total	$ 2,069,664	$ 737,675			$ 1,956,989	$ 763,183		

2004

Functional Class of Property	Regulated: Property, Plant and Equipment (in thousands)	Regulated: Accumulated Depreciation (in thousands)	Regulated: Annual Composite Depreciation Rate	Regulated: Depreciable Life Ranges (in years)	Nonregulated: Property, Plant and Equipment (in thousands)	Nonregulated: Accumulated Depreciation (in thousands)	Nonregulated: Annual Composite Depreciation Rate	Nonregulated: Depreciable Life Ranges (in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,658,552	$ 761,085	2.9%	40-50
Transmission	432,714	186,052	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,300,252	448,762	3.6%	12-56	-	-	N.M.	N.M.
CWIP	34,631	1,016	N.M.	N.M.	97,112	52	N.M.	N.M.
Other	167,986	74,984	10.3%	N.M.	25,828	3,506	N.M.	N.M.
Total	$ 1,935,583	$ 710,814			$ 1,781,492	$ 764,643		

2003

Functional Class of Property	Regulated: Annual Composite Depreciation Rate	Regulated: Depreciable Life Ranges (in years)	Nonregulated: Annual Composite Depreciation Rate	Nonregulated: Depreciable Life Ranges (in years)
Production	N.M.	N.M.	3.0 %	40-50
Transmission	2.3%	33-50	N.M.	N.M.
Distribution	3.6%	12-56	N.M.	N.M.
Other	9.9%	N.M.	N.M.	N.M.

2005	I&M Regulated				PSO Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 3,128,078	$ 1,901,698	3.8%	40-119	$ 1,072,928	$ 639,256	2.7%	30-57
Transmission	1,028,496	401,024	1.9%	30-65	479,272	153,998	2.1%	40-75
Distribution	1,029,498	335,642	4.1%	12-65	1,140,535	262,763	3.1%	25-65
CWIP	311,080	(1,544)	N.M.	N.M.	90,455	(7,798)	N.M.	N.M.
Other	309,217	79,741	11.7%	N.M.	207,211	127,639	7.4%	N.M.
Total	$ 5,806,369	$ 2,716,561			$ 2,990,401	$ 1,175,858		

	I&M Nonregulated				PSO Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 155,913	$ 105,997	3.4%	N.M.	$ 4,594	$ -	N.M.	N.M.

2004	I&M Regulated				PSO Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 3,122,883	$ 1,813,130	3.7%	40-119	$ 1,072,022	$ 619,348	2.7%	30-57
Transmission	1,009,551	391,980	1.9%	30-65	468,735	150,799	2.3%	40-75
Distribution	990,826	329,665	4.1%	12-65	1,089,187	260,623	3.3%	25-65
CWIP	163,515	(1,545)	N.M.	N.M.	41,028	(9,899)	N.M.	N.M.
Other	275,627	70,249	11.2%	N.M.	200,044	96,242	7.9%	N.M.
Total	$ 5,562,402	$ 2,603,479			$ 2,871,016	$ 1,117,113		

	I&M Nonregulated				PSO Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 155,078	$ 104,643	3.4%	N.M.	$ 4,823	$ 422	N.M.	N.M.

2003	I&M Regulated		PSO Regulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.8%	40-119	2.7%	30-57
Transmission	1.9%	30-65	2.4%	40-75
Distribution	4.2%	12-65	3.4%	25-65
Other	11.8%	N.M.	9.7%	N.M.

OPCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,278,553	$ 1,876,732	2.8%	35-61
Transmission	1,002,255	403,260	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,258,518	338,652	3.9%	12-55	-	-	N.M.	N.M.
CWIP	66,103	(1,361)	N.M.	N.M.	624,065	1,494	N.M.	N.M.
Other	234,569	110,743	10.7%	N.M.	59,225	9,379	3.0%	N.M.
Total	$ 2,561,445	$ 851,294			$ 4,961,843	$ 1,887,605		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,127,284	$ 1,785,442	2.8%	35-42
Transmission	978,492	396,365	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,202,550	323,765	4.0%	12-55	-	-	N.M.	N.M.
CWIP	48,732	(1,454)	N.M.	N.M.	192,225	493	N.M.	N.M.
Other	248,748	112,628	10.1%	N.M.	60,740	15,964	3.0%	N.M.
Total	$ 2,478,522	$ 831,304			$ 4,380,249	$ 1,801,899		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	2.8%	35-42
Transmission	2.3%	27-70	N.M.	N.M.
Distribution	4.0%	12-55	N.M.	N.M.
Other	10.5%	N.M.	3.0%	N.M.

SWEPCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 912,044	$ 577,611	3.3%	30-57	$ 748,348	$ 483,743	3.3%	30-57
Transmission	645,297	201,521	2.8%	40-55	-	-	N.M.	N.M.
Distribution	1,153,026	339,258	3.6%	16-65	-	-	N.M.	N.M.
CWIP	81,437	(73)	N.M.	N.M.	22,738	667	N.M.	N.M.
Other	362,572	134,575	7.2%	N.M.	81,177	38,914	N.M.	N.M.
Total	$ 3,154,376	$ 1,252,892			$ 852,263	$ 523,324		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 916,912	$ 566,513	3.3%	30-57	$ 746,249	$ 470,541	3.3%	30-57
Transmission	632,964	188,455	2.8%	40-55	-	-	N.M.	N.M.
Distribution	1,114,480	318,915	3.6%	16-65	-	-	N.M.	N.M.
CWIP	40,647	6,202	N.M.	N.M.	8,205	1,537	N.M.	N.M.
Other	358,119	126,480	6.9%	N.M.	74,932	32,207	N.M.	N.M.
Total	$ 3,063,122	$ 1,206,565			$ 829,386	$ 504,285		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.3%	30-57	3.3%	30-57
Transmission	2.8%	40-55	N.M.	N.M.
Distribution	3.6%	16-65	N.M.	N.M.
Other	8.0%	N.M.	N.M.	N.M.

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.66, $0.65, and $0.41 per ton in 2005, 2004 and 2003, respectively. In 2004, average amortization rates increased from 2003 due to a lower tonnage nomination from the power plant yielding a higher cost per ton.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal cost is expensed as incurred (see "Accounting for Asset Retirement Obligations" section of this note).

Accounting for Asset Retirement Obligations (ARO)

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

In the fourth quarter of 2005, the Registrant Subsidiaries recorded ARO in accordance with FIN 47 related to the removal and disposal of asbestos in general buildings and generating plants (See "FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligation" (FIN 47)" and "Cumulative Effect of Accounting Changes" sections of Note 2).

As of December 31, 2005 and 2004, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $870 million and $791 million, respectively. These assets are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets. As of December 31, 2004, the fair value of TCC's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $143 million. These assets related to the STP nuclear plant, which was sold in 2005. These assets were included in Assets Held for Sale – Texas Generation Plants on TCC's 2004 Consolidated Balance Sheet. Due to the sale, we are no longer responsible for the STP decommissioning liabilities.

The following is a reconciliation of the 2004 and 2005 aggregate carrying amounts of ARO by Registrant Subsidiary:

	ARO at January 1, 2004, Including Held for Sale	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2004, Including Held for Sale
AEGCo (a)	$ 1,126	$ 90	$ -	$ -	$ -	$ 1,216
APCo (a)	21,776	1,740	-	(469)	1,579	24,626
CSPCo (a)	8,740	703	-	(2)	2,144	11,585
I&M (a)(b)	553,219	39,825	-	-	118,725	711,769
OPCo (a)	42,656	3,430	-	-	(480)	45,606
SWEPCo (c)	8,429	1,274	17,658	-	-	27,361
TCC (d)	218,771	16,726	-	-	13,375	248,872

	ARO at January 1, 2005, Including Held for Sale	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2005
AEGCo (a)(e)	$ 1,216	$ 98	$ 56	$ -	$ -	$ 1,370
APCo (a)(e)	24,626	1,928	8,972	(32)	2	35,496
CSPCo (a)(e)	11,585	864	1,981	(9)	3,423	17,844
I&M (a)(b)(e)	711,769	47,368	5,801	-	(26,979)	737,959
KPCo (e)	-	-	1,190	-	-	1,190
OPCo (a)(e)	45,606	3,665	9,513	-	6,773	65,557
PSO (e)	-	-	6,056	-	-	6,056
SWEPCo (a)(c)(e)(f)	27,361	1,491	18,071	(3,449)	(397)	43,077
TCC (d)(e)	248,872	7,549	1,165	(256,421)	-	1,165
TNC (e)	-	-	13,514	-	-	13,514

(a) Includes ARO related to ash ponds.

(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant ($731 million and $711 million at December 31, 2005 and 2004, respectively).

(c) Includes ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC.

(d) Includes ARO related to nuclear decommissioning costs for TCC's share of STP which is included in Liabilities Held for Sale – Texas Generation Plants on TCC's 2004 Consolidated Balance Sheet. STP was sold in May 2005 (see Note 10).

(e) Includes ARO related to asbestos removal.

(f) The current portion of SWEPCo's ARO, totaling $2 million, is included in Other in the Current Liabilities section of SWEPCo's 2005 Consolidated Balance Sheet.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For Nonregulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized for 2005, 2004 and 2003 are as follows:

	2005	2004	2003
		(in millions)	
AEGCo	$ 0.3	$ -	$ -
APCo	16.7	14.7	8.5
CSPCo	3.1	6.1	6.3
I&M	8.8	4.1	8.2
KPCo	0.6	0.5	1.7
OPCo	17.8	6.3	5.0
PSO	1.5	0.6	0.8
SWEPCo	3.6	1.1	1.7
TCC	2.5	1.9	1.1
TNC	1.1	0.6	0.8

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

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

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt.

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales or delivery when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and certain subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billings.

AEP Credit, Inc. factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 16).

Concentrations of Credit Risk and Significant Customers

TNC and TCC have significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable – Customers as of December 31:

	2005	2004	2003
		(in percentage)	
TCC –ERCOT and Centrica			
Percentage of Operating Revenues	29%	72%	55%
Percentage of Accounts Receivable - Customers	7	54	N/A
TNC –ERCOT and Centrica			
Percentage of Operating Revenues	27	57	55
Percentage of Accounts Receivable - Customers	12	59	N/A

We monitor credit levels and the financial condition of our customers on a continuing basis to minimize credit risk. We believe adequate provision for credit loss has been made in the accompanying Registrant Financial Statements.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). For TCC & TNC, their deferred fuel balances were included in their True-up Proceedings (see Note 6). See Note 5 for the amount of deferred fuel costs by Registrant Subsidiary. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been capped, frozen or suspended for a period of years, fuel costs impact earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze ended on March 1, 2004. Through subsequent orders, the Indiana Utility Regulatory Commission (IURC) authorized the billing of capped fuel rates on an interim basis until April 1, 2005 and subsequently extended these rates until June 30, 2007. In West Virginia, the fuel clause is suspended indefinitely. See Notes 4 and Note 6 for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains and losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, Registrant Subsidiaries record them as assets on the balance sheet. Registrant Subsidiaries test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the Registrant Subsidiaries write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, AEP's west zone is short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEP's west zone where we are short capacity, prior to settlement the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period are recognized as Revenues. If the contract results in the physical delivery of power, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded gross as Purchased Energy for Resale. If the contract does not physically deliver, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded as Revenues in the financial statements on a net basis (see "Derivatives and Hedging" section of Note 13).

Energy Marketing and Risk Management Activities

Registrant Subsidiaries engage in wholesale electricity and coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where Registrant Subsidiaries own assets. Registrant Subsidiaries' activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, Registrant Subsidiaries recorded wholesale marketing and risk management activities using the MTM method of accounting.

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

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

All of the Registrant Subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For all contracts the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in revenues on a net basis. Unrealized mark-to-market losses and gains are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions, a future cash flow (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the financial statements in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and depending upon the specific nature of the risk being hedged, subsequently reclassified into Revenues or fuel expenses in the financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the financial statements immediately (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" section of Note 13).

Construction Projects for Outside Parties

TCC and TNC engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred. Such revenue and related expenses are included in Other Nonaffiliated Revenue and Other Operation Expenses, respectively, in the financial statements. Contractually billable expenses not yet billed, are included in Current Assets as Unbilled Construction Costs in the financial statements.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure that all deferred costs are fully amortized by the end of the refueling cycle.

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that Registrant Subsidiaries will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

Income Taxes and Investment Tax Credits

Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

Excise Taxes

Registrant Subsidiaries, as agents for some state and local governments, collect from customers certain excise taxes levied by those state or local governments on customers. Registrant Subsidiaries do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

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

Registrant Subsidiaries classify instruments that have an unconditional obligation requiring them to redeem the instruments by transferring an asset at a specified date as liabilities on their balance sheets. Those instruments consist of Cumulative Preferred Stock Subject to Mandatory Redemption as of December 31, 2004. Beginning July 1, 2003, the Registrant Subsidiaries classify dividends on these mandatorily redeemable preferred shares as Interest Expense. In accordance with SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," dividends from prior periods remain classified as preferred stock dividends, a component of Preferred Stock Dividend Requirements, on their financial statements.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain Registrant Subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

SWEPCo is the only Registrant Subsidiary with an intangible asset with a finite life and amortizes the asset over its estimated life to its residual value (see Note 3). The Registrant Subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2005 and 2004.

Emission Allowances

The Registrant Subsidiaries, except AEG, record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlement received at no cost from the Federal EPA. They follow the inventory model for all allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets-Deferred Charges and Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Current Assets-Prepayments and Other for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries revenue optimization strategy for their operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- acceptable investments (rated investment grade or above);
- maximum percentage invested in a specific type of investment;
- prohibition of investment in obligations of the applicable company or its affiliates; and
- withdrawals permitted only for payment of decommissioning costs and trust expenses.

Trust funds are maintained for each regulatory jurisdiction and managed by external investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to I&M's Cook Plant. In 2004, amounts for TCC are included in Assets Held for Sale-Texas Generation Plants for amounts relating to its ownership in STP. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

The following is a summary of I&M's nuclear trust fund investments at December 31:

	2005				2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash	$ 21	$ -	$ -	$ 21	$ 20	$ -	$ -	$ 20
Debt Securities	691	7	(7)	691	634	8	(3)	639
Equity Securities	277	148	(3)	422	282	114	(2)	394
Spent Nuclear Fuel and Decommissioning Trusts	$ 989	$ 155	$ (10)	$ 1,134	$ 936	$ 122	$ (5)	$ 1,053

Proceeds from sales of nuclear trust fund investments were $557 million, $863 million and $580 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $607 million, $901 million and $657 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $4 million, $10 million and $26 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $16 million, $17 million and $5 million in 2005, 2004 and 2003, respectively.

The following is a summary of TCC's nuclear trust fund investments at December 31:

	2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash	$ 2	$ -	$ -	$ 2
Debt Securities	57	2	(1)	58
Equity Securities	48	35	-	83
Decommissioning Trusts Included in Assets Held for Sale	$ 107	$ 37	$ (1)	$ 143

Proceeds from sales of nuclear trust fund investments were $150 million, $87 million and $41 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $154 million, $100 million and $51 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $8.6 million, $2.5 million and $0.5 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $1.8 million, $0.9 million and $1.4 million in 2005, 2004 and 2003, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2005 for I&M is as follows:

	Fair Value (in millions)
Within 1 year	$ 17
1 year – 5 years	298
5 years – 10 years	173
After 10 years	203
	$ 691

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss). There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the common shareholder's equity section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of December 31, 2005 and 2004 is shown in the following table.

Components	December 31, 2005	December 31, 2004
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (16,421)	$ (9,324)
CSPCo	(859)	1,393
I&M	(3,467)	(4,076)
KPCo	(194)	813
OPCo	755	1,241
PSO	(1,112)	400
SWEPCo	(5,852)	(820)
TCC	(224)	657
TNC	(111)	285
Minimum Pension Liability:		
APCo	$ (189)	$ (72,348)
CSPCo	(21)	(62,209)
I&M	(102)	(41,175)
KPCo	(29)	(9,588)
OPCo	-	(75,505)
PSO	(152)	(325)
SWEPCo	(277)	(360)
TCC	(928)	(4,816)
TNC	(393)	(413)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo and OPCo are wholly-owned subsidiaries of AEP and PSO, SWEPCo, TCC and TNC are owned by a wholly-owned subsidiary of AEP; therefore, none are required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

The Registrant Subsidiaries' Statements of Operations were converted from a utility format presentation where only regulated cost-of-service items were reflected in Operating Income to a commercial format presentation where nonutility items are reflected as components of Operating Income. Also, in the Balance Sheets under the commercial format we include nonutility property in Other Property, Plant and Equipment.

In addition, in the Registrant Subsidiaries' Statements of Operations, we reclassified the consumption of emission allowances and consumption of chemicals used in the generation of power from Other Operation to Fuel and Other Consumables Used for Electric Generation as follows:

	Year Ended December 31, 2004	2003
	(in thousands)	
AEGCo	$ -	$ -
APCo	12,233	10,320
CSPCo	19,736	17,308
I&M	6,693	4,505
KPCo	4,425	4,826
OPCo	68,237	57,927
PSO	24	-
SWEPCo	826	-
TCC	1,213	-
TNC	5	-

The Registrant Subsidiaries also reclassified the net gain or loss on the sales of emission allowances from Other Operation to Revenues. These reclassifications were not material for 2004 or 2003.

In the Balance Sheets for the AEP West companies, we netted certain Accounts Receivable - Customers and Accounts Payable – General consistent with the netting performed by the AEP East companies and to more accurately reflect the net positions with risk management activity counterparties. The decrease (increase) in Accounts Receivable – Customers and in Accounts Payable - General were as follows:

	December 31, 2004
	(in thousands)
PSO	$ 1,993
SWEPCo	(383)
TCC	17,470
TNC	8,367

These revisions had no impact on our previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

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

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

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." A cumulative effect of a change in accounting principle will be recorded for the effect of initially applying the statement.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. SFAS 154 was effective beginning January 1, 2006 and will be applied as necessary.

FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

The Registrant Subsidiaries adopted FIN 47 during the fourth quarter of 2005. In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

The Registrant Subsidiaries completed a review of their FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In the fourth quarter of 2005, the Registrant Subsidiaries recorded conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to regulated operations was generally charged to regulatory liability. The Registrant Subsidiaries with nonregulated operations recorded an unfavorable cumulative effect related to asbestos removal for those operations.

The following table shows the liability for conditional ARO and cumulative effect recorded for FIN 47 by Registrant Subsidiary:

	Liability Recorded	Cumulative Effect	
		Pretax	Net of Tax
		(in thousands)	
AEGCo	$ 56	$ -	$ -
APCo	8,972	(3,470)	(2,256)
CSPCo	1,981	(1,292)	(839)
I&M	5,801	-	-
KPCo	1,190	-	-
OPCo	9,513	(7,039)	(4,575)
PSO	6,056	-	-
SWEPCo	6,702	(1,926)	(1,252)
TCC	1,165	-	-
TNC	13,514	(13,034)	(8,472)

The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which they have assets. Generally, such easements are perpetual and require only the retirement and removal of the Registrant Subsidiaries' assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use the facilities indefinitely. The retirement obligations would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements.

Pro forma net income is not presented for the years ended December 31, 2004 and 2003 because the pro forma application of FIN 47 would result in pro forma net income not materially different from the actual amounts reported during those periods.

The following is a summary by Registrant Subsidiary of the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted as of the beginning of each period presented:

	December 31, 2004	December 31, 2003
	(in thousands)	
AEGCo	$ 53	$ 50
APCo	8,434	7,928
CSPCo	1,862	1,750
I&M	5,453	5,126
KPCo	1,119	1,052
OPCo	8,943	8,407
PSO	5,693	5,352
SWEPCo	6,757	6,351
TCC	1,085	1,020
TNC	12,704	11,942

See "Accounting for Asset Retirement Obligations (ARO)" section of Note 1 for further discussion.

EITF Issue 03-13 "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations"

This issue developed a model for evaluating cash flows in determining whether cash flows have been or will be eliminated and also what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We applied this issue to components we disposed or classified as held for sale.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges fininished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

Future Accounting Changes

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

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on those deliberations and oral decisions, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in TCC's Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax (see "Texas True-up Proceedings" section of Note 6).

In the fourth quarter of 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis, including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in a nonaffiliated utility's true-up order (see "Wholesale Capacity Auction True-up and Stranded Plant Cost" section of Note 6). These net adjustments were recorded as an extraordinary item of $121 million net of tax in accordance with SFAS 101 and are reflected in TCC's Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax.

In 2003, an extraordinary item of $177 thousand, net of tax of $95 thousand, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC order dated December 24, 2003 approving a settlement.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 "Accounting for Contracts Included in Energy Trading and Risk Management Activities," and related interpretive guidance. The Registrant Subsidiaries except PSO and AEGCo have recorded net of tax charges against net income in Cumulative Effect of Accounting Changes on their financial statements in 2003. These amounts are recognized as the positions settle.

Asset Retirement Obligations

In 2003, certain Registrant Subsidiaries recorded a cumulative effect of accounting change for ARO in accordance with SFAS 143.

In the fourth quarter of 2005, certain Registrant Subsidiaries recorded a net of tax loss as a cumulative effect of accounting change for ARO in accordance with FIN 47.

The following is a summary by Registrant Subsidiary of the cumulative effect of changes in accounting principles recorded in 2005 and 2003 for the adoptions of FIN 47, SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	2005 FIN 47 Cumulative Effect		2003 SFAS 143 Cumulative Effect		2003 EITF 02-3 Cumulative Effect	
	(in millions)					
	Pretax Income (Loss)	Net of Tax Income (Loss)	Pretax Income (Loss)	Net of Tax Income (Loss)	Pretax Income (Loss)	Net of Tax Income (Loss)
APCo	$ (3.5)	$ (2.3)	$ 128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	(1.3)	(0.8)	49.0	29.3	(3.1)	(2.0)
I&M	-	-	-	-	(4.9)	(3.2)
KPCo	-	-	-	-	(1.7)	(1.1)
OPCo	(7.0)	(4.6)	213.6	127.3	(4.2)	(2.7)
SWEPCo	(1.9)	(1.3)	13.0	8.4	0.2	0.1
TCC	-	-	-	-	0.2	0.1
TNC	(13.0)	(8.5)	4.7	3.1	-	-

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the Registrant Subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $15.8 million at December 31, 2005 and $18.8 million at December 31, 2004, net of accumulated amortization and is included in Deferred Charges and Other on SWEPCo's Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization are:

	Amortization Life	December 31, 2005 Gross Carrying Amount	December 31, 2005 Accumulated Amortization	December 31, 2004 Gross Carrying Amount	December 31, 2004 Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$ 29.4	$ 13.6	$ 29.4	$ 10.6

Amortization of the intangible asset was $3 million per year for 2005, 2004 and 2003. SWEPCo's estimated total amortization is $3 million per year for 2006 through 2010 and $1 million in 2011.

4. RATE MATTERS

APCo Virginia Environmental and Reliability Costs – Affecting APCo

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request included incurred and projected costs from July 1, 2004 through June 30, 2006 which relate to (i) environmental controls on coal-fired generators to meet the first phase of the final Clean Air Interstate Rule and Clean Air Mercury Rule issued in 2005, (ii) the Wyoming-Jacksons Ferry 765 kilovolt transmission line construction and (iii) other incremental T&D system reliability work.

In the filing, APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. In October 2005, the Virginia SCC denied APCo's request to place the proposed cost recovery surcharge in effect, on an interim basis subject to refund. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the public hearing in this case which began on February 27, 2006.

The Virginia SCC also ruled that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, the order permitted APCo to update its request to reflect additional actual costs and/or present additional evidence. Accordingly, in November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery of E&R costs to $21 million of actual incremental E&R costs incurred during the period July 1, 2004 through September 30, 2005.

Through December 31, 2005, APCo has deferred $24 million of recorded E&R costs. It has not yet recorded $4 million of such costs which represent equity carrying costs that are not recognized until collected through regulated rates. In addition, APCo has reversed $5 million of AFUDC/interest capitalized through December 31, 2005 related to incremental E&R capital investments that would have been duplicative of a portion of the deferred E&R carrying costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to include $20 million of incremental E&R costs in its electric rates. The staff also recommended the disallowance of the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that have been established as a regulatory asset as of December 31, 2005. We believe the staff's position is contrary to the Virginia SCC's October 2005 order, which denied APCo's request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs after the commission examines and approves such costs. If the Virginia SCC denies recovery of any of APCo's deferred E&R costs, the denial could adversely impact future results of operations and cash flows. Hearings began on February 27, 2006.

APCo West Virginia Rate Case – Affecting APCo

In August 2005, APCo collectively filed an application with the WVPSC seeking an initial increase in their retail rates of approximately $77 million. The initial increase requests approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounts for $65 million of the initial increase. The request also seeks approval to implement a system reliability tracker which accounts for $9 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins and transmission items.

In addition, APCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively.

APCo has a regulatory liability of $52 million for pre-suspension, over-recovered ENEC costs. APCo proposed to apply this $52 million, along with a carrying cost, as a reduction to any future under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism.

In January 2006, APCo submitted supplemental testimony addressing the Ceredo Generating Station acquisition (see "Acquisitions" section of Note 10) and certain revisions to their filing. The supplemental filing revised the initial requested increase of $77 million downward to $69 million. APCo revised the supplemental increases downward to $43 million, $8 million and $36 million, effective on January 1, 2007, 2008 and 2009, respectively.

In January 2006, APCo, WPCo and the WVPSC staff filed a joint motion requesting a change in the procedural schedule. The motion, as modified, requests that hearings begin in April 2006, new rates go into effect on July 28, 2006 and deferral accounting for over - or under – recovery of the ENEC costs begins July 1, 2006. In response to that motion, the WVPSC approved the proposed schedule including the commencement date for the ENEC deferral accounting. At this time, management cannot predict the ultimate effect on APCo's future revenues, results of operations and cash flows of APCo's base rate increase proceeding in West Virginia.

I&M Indiana Settlement Agreement – Affecting I&M

In 2003, I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain parties to the negotiations reached a settlement. The IURC approved the settlement agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate. Total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor was adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at the Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate). If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If the Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

I&M experienced a cumulative under-recovery of fuel costs for the period March 2004 through December 2005 of $12 million. Since I&M expects that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, I&M recorded $9 million and $3 million of under-recoveries as fuel expense in 2005 and 2004, respectively. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, future results of operations and cash flows would be adversely affected.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

I&M Depreciation Study Filing– Affecting I&M

In December 2005, I&M filed a petition with the IURC which seeks authorization effective January 1, 2006 to revise the book depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in customers' electric service rates. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. If approved, the book depreciation expense reduction would increase earnings, but would not impact cash flows. Hearings are scheduled to begin in May 2006. When approved by the IURC, I&M will prospectively revise its book depreciation rates and, if appropriate, currently adjust its book depreciation expense to the approved effective date.

KPCo Rate Filing – Affecting KPCo

In September 2005, KPCo filed a request with the Kentucky Public Service Commission (KPSC) to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase included a return on common equity of 11.5% or $26 million, the impact of reduced through-and-out transmission revenues of $10 million, recovery of additional AEP Power Pool capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. In February 2006, KPCo executed and submitted a settlement agreement to the KPSC for its approval. The major terms of the agreement are as follows: KPCo will receive a $41 million increase in revenues effective March 30, 2006, KPCo will retain its existing environmental surcharge tariff and KPCo will continue to include in the calculation of its annual depreciation expense the depreciation rates currently approved and utilized as a result of KPCo's 1991 rate case. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes. The KPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power and its Possible Impact on AEP East Companies – Affecting PSO and AEP East companies

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO offered to collect those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs, future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between and among AEP East companies and AEP West companies and specifically PSO was inconsistent with the FERC-approved Operating Agreement and SIA and that the AEP West companies should have been allocated greater margins. The parties objected to the inclusion of mark-to-market amounts in developing the allocation base. In addition, an intervenor recommended that $9 million of the $42 million related to the 2002 reallocation not be recovered from Oklahoma retail customers because that amount was not refunded by PSO's affiliated AEP West companies to their wholesale customers outside of Oklahoma.

The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002. In July 2005, the OCC staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East companies and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins allocated to PSO and thus, a reduction in its recoverable fuel costs through December 2004 in a range of $38 million to $47 million.

In January 2006, the OCC staff and intervenors issued supplemental testimony proposing that the OCC offset the under-recovered fuel clause deferral inclusive of the $42 million with off-system sales margins of $27 million to $37 million through December 2004. The OCC staff also recommended a disallowance of $6 million. Hearings were held in early February 2006 to address the issues. PSO does not agree with the intervenors' and the OCC staff's recommendations and will defend vigorously its position.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. Intervenors appealed the ALJ ruling to the OCC. The OCC has not ruled on the intervenors' appeal or the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. The Court agreed that the FERC had jurisdiction over the SIA and that the sole remedy is at the FERC.

If the OCC decides to provide for additional off-system sales margins, it could adversely affect future results of operations and cash flows. However, if the position taken by the federal court in Texas is applied to PSO's case, the OCC would be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins due to a lack of jurisdiction. The OCC or another party could file a complaint at the FERC which could ultimately be successful, and which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To-date there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on future results of operations, cash flows and financial condition.

In April 2005, the OCC heard arguments from intervenors that requested the OCC conduct a prudence review of PSO's fuel and purchased power practices for 2003. In June 2005, the OCC asked its staff to conduct that review. The OCC staff is scheduled to file its testimony in March 2006 and the hearings are scheduled for May 2006.

PSO 2005 Fuel Factor Filing – Affecting PSO

In November 2005, PSO submitted to the OCC staff an interim adjustment to PSO's annual fuel factors. PSO's new factors were based on increased natural gas and purchased power market prices, as well as past under-recovered fuel costs. PSO implemented the new fuel factors in its December 2005 billing. The new fuel factors are estimated to increase 2006 revenues by approximately $349 million. At December 31, 2005, PSO had a deferred under-recovered fuel balance of $109 million, which includes interest and the $42 million discussed above in "PSO Fuel and Purchased Power and its Possible Impact on AEP East companies." This fuel factor adjustment will increase cash flows without impacting PSO's results of operations as any over or under-recovery of fuel cost will be deferred as a regulatory liability or regulatory asset.

PSO Rate Review – Affecting PSO

PSO was involved in an OCC staff-initiated base rate review, which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates by $41 million, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provided for a $7 million annual base revenue reduction offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminated a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provided for recovery, over 24 months, of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulated that PSO may not file for a base rate increase before April 1, 2006. The OCC approved the stipulation in May 2005 and new base rates were implemented in June 2005.

PSO 2005 Vegetation Management Filing – Affecting PSO

In June 2005, PSO filed testimony to adjust its vegetation management rate rider from the OCC-approved $12 million to $27 million. In November 2005, the OCC issued a final order approving an increase to the cap on the PSO vegetation management rider to $24 million, which is in addition to the $6 million vegetation management expenses currently included in base rates. The final order also provided for the recovery of carrying and other costs associated with converting overhead distribution lines to underground lines. PSO does not anticipate any material effect on income for the incremental costs associated with the increased cap as the incremental costs will be deferred and expensed in the future when the rate rider revenues are recognized.

SWEPCo PUCT Staff Review of Earnings – Affecting SWEPCo

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Management is unable to predict the outcome of this initial report on SWEPCo's future revenues, results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Issues – Affecting SWEPCo

In November 2005, the Louisiana Public Service Commission (LPSC) amended an inquiry into the operation of the fuel adjustment clause recovery mechanisms of other Louisiana electric utilities to include SWEPCo. The inquiry was initiated to determine whether utilities had purchased fuel and power at the lowest possible price and whether suppliers offered competitive prices for fuel and purchased power during the period of January 1, 2005 through October 31, 2005.

In December 2005, the LPSC initiated a new audit of SWEPCo's historical fuel costs which will cover the years 2003 and 2004, pursuant to the LPSC's general order requiring biennial fuel reviews. Management cannot predict the outcome of these audits/reviews, but believes that SWEPCo's fuel and purchased power procurement practices were prudent and costs were properly incurred. If the LPSC disagrees and disallows fuel or purchased power costs incurred by SWEPCo, it would have an adverse effect on SWEPCo's future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing – Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSC's merger order also provided that SWEPCo's base rates were capped through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony was filed in January 2005 and subsequent deposition proceedings are in process. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact SWEPCo's future results of operations and cash flows.

TCC Rate Case – Affecting TCC

In August 2005, the PUCT issued an order in a base rate proceeding initiated in 2003 by a Texas municipality. The order reduced TCC's annual base rates by $9 million. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. Tariffs were approved and the rate change was implemented effective September 6, 2005. TCC and other parties have appealed this proceeding to the Texas District Court. No schedule has been set for hearing the appeals. Management cannot predict the ultimate outcome of these appeals. Also, in the third quarter of 2005, TCC reclassified $126 million of asset removal costs from Accumulated Depreciation and Amortization to Regulatory Liabilities and Deferred Investment Tax Credits on TCC's Consolidated Balance Sheets based on a depreciation study prepared by TCC and approved by the PUCT.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court on the loss of load issue, but otherwise affirmed its decision. The amount of unaccounted-for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. AEP's 2005 pretax earnings were adversely affected by $3 million because of this decision. In a decision on rehearing in February 2006, the Texas Court of Appeals no longer is directing on remand that the unaccounted for energy issue be reconsidered solely based on the existing record. The prior ruling would have prevented the PUCT from considering additional evidence on the $3 million adjustment. Management cannot predict the outcome of further appeals but a reversal of the favorable court of appeals decision regarding the loss of load issue would adversely impact TCC's and TNC's results of operations and cash flows.

RTO Formation/Integration – Affecting APCo, CSPCo, I&M, KPCo and OPCo

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs and carrying costs incurred to originally form a new RTO (the Alliance) and subsequently to integrate into an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The formation and integration costs included in AEP's application by company follows:

Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)	
APCo	$ 4.8	$ 5.1
CSPCo	2.0	2.2
I&M	3.8	3.8
KPCo	1.1	1.1
OPCo	5.5	5.7

The FERC approved AEP's application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years consistent with a March 2005 requested rate recovery period discussed below. The total amortization related to such costs was $5 million in 2005. The AEP East companies did not record $5 million and $4 million of equity carrying costs in 2005 and 2004, respectively, which are not recognized until collected.

The AEP East companies' deferred unamortized RTO formation/integration costs were as follows:

	December 31, 2005		December 31, 2004	
	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)			
APCo	$ 4.1	$ 4.9	$ 4.7	$ 4.7
CSPCo	1.7	1.9	2.0	1.8
I&M	3.2	3.7	3.5	3.8
KPCo	1.0	1.1	1.0	1.2
OPCo	4.7	5.1	5.3	5.3

In March 2005, AEP and two other utilities jointly filed a request with the FERC to recover their deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. In May 2005, the FERC issued an order denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the compliance filing in May 2005. In June 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In October 2005, the FERC granted AEP's June 2005 rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. Also, the FERC, in its order, dismissed the May 2005 compliance filing as moot. Settlement discussions are still underway, and a result that would collect a portion of the costs in other PJM zones is likely, though not yet assured.

In March 2005, AEP also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed below in the "AEP East Transmission Requirement and Rates" section). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs).

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM OATT to recover the amount of deferred RTO formation costs to be amortized, determined to be $2 million per year. The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In a December 2005 order, the Public Utilities Commission of Ohio (PUCO) approved recovery of the amortization of RTO Formation/Integration Costs through a Transmission Cost Recovery Rider (TCRR). In Kentucky and West Virginia, filings have been made to recover the amortization of these costs (see "KPCo Rate Filing" section of this Note). The Indiana service territory of I&M is subject to a rate freeze until June 2007, so recovery will be delayed until the freeze ends.

Until all the AEP East companies can adjust their retail rates to recover the amortization of both RTO related deferred costs, their results of operations and cash flows will be adversely affected by the amortizations. The proposed FERC settlement would allow and establish a reasonable carrying charge for the deferred costs. If the FERC or any state regulatory authority was to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs, it would have an adverse impact on the AEP East companies' future results of operations and cash flows. If the FERC approves a carrying charge rate that is lower than the carrying charge recognized to date, it could have an adverse effect on the AEP East companies' future results of operations and cash flows.

Transmission Rate Proceedings at the FERC - Affecting APCo, CSPCo, I&M, KPCo and OPCo

<u>FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue</u>

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through-and-out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint).

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004.

The elimination of the T&O charges for transactions between the two RTOs reduces the transmission service revenues collected by the RTOs and thereby, reduces the revenues received by transmission owners, including the AEP East companies, under the RTOs' revenue distribution protocols.

As a result of settlement negotiations in early 2004, the effective date of the SECA transition was delayed by the FERC. The delay was to give parties an opportunity to create a new regional rate regime. When the parties were unable to agree on a single regional rate proposal, the FERC ordered the two-year SECA transition period shortened to sixteen months, effective on December 1, 2004, continuing through March 31, 2006. The FERC has set SECA rate issues for hearing and indicated that the SECA rates are being recovered subject to refund or surcharge. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. At this time, management is unable to determine the probable outcome of the FERC's SECA rate proceeding and its impact on the AEP East companies' future results of operations and cash flows. The AEP East companies recognized net SECA revenues as follows:

	2005	December 2004
	(in millions)	
APCo	$ 41.0	$ 3.5
CSPCo	22.3	2.0
I&M	23.7	2.3
KPCo	9.7	0.8
OPCo	30.8	2.8

AEP East Transmission Revenue Requirement and Rates

In the March 2005 FERC filing discussed in the "RTO Formation/Integration Costs" section above, AEP proposed a two-step increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities, and retail choice customers with load delivery points in the AEP zone of PJM. In December 2005, the FERC approved an uncontested settlement allowing our wholesale transmission rates to increase in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues are expected to be eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when AEP's Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under the Highway/Byway rate design proposed by AEP and AP, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kilovolt (kV) or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design which reflects the cost of the facilities in the corporate zone in which the transmission facilities are owned (License Plate Rate). The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the AEP East transmission-owning companies.

A competing Highway/Byway proposal filed by others would also produce net revenues to the AEP East transmission-owning companies, but at a much lower level. Both proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM License Plate Rate design. A group of LSEs has also made a proposal that would include 500 kV and higher existing facilities, and some facilities at lower voltages in the highway rate.

In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal. The case is scheduled for hearing in April 2006. AEP management cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on AEP revenues, compared to the License Plate Rates that will otherwise prevail beginning April 1, 2006 when the transitional SECA rates expire.

As of December 31, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will not be sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues will require cost recovery through retail rate proceedings. Rate requests are pending in Kentucky and West Virginia that address the reduction in FERC transmission revenues, (see "KPCo Rate Filing" section of this Note). In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. Management is unable to predict when and if the effect of the loss of transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

The AEP East companies' future results of operations, cash flows and financial condition would be adversely affected if:

- the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or
- the newly approved AEP zonal transmission rates are not sufficient to replace the lost T&O/SECA revenues, or
- the FERC's review of our current SECA rates results in a rate reduction which is subject to refund, or
- any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail rates on a timely basis, or
- the FERC does not approve a new regional rate within PJM.

FERC Market Power Mitigation – Affecting AEP East Companies and AEP West Companies

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

In a December 2004 order, the FERC affirmed the conclusions that the AEP System passed both market power screen tests in all areas except SPP. Because the AEP System did not pass the market share screen in SPP, the FERC initiated proceedings under Section 206 of the Federal Power Act in which the AEP West companies are rebuttably presumed to possess market power in SPP. In February 2005, although management continued to believe the AEP System did not possess market power in SPP, the AEP West companies filed a response and proposed tariff changes to address the FERC's market-power concerns. The proposed tariff change would apply to sales that sink within the service territories of PSO, SWEPCo and TNC within SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps.

In July 2005, the FERC accepted for filing the amended tariffs effective March 6, 2005 and set for hearing three aspects of the proposed tariffs. Two parties intervened in the proceeding protesting the proposed cost-based tariffs. In October 2005, all parties and the FERC staff entered into a settlement agreement adopting AEP's proposed tariffs with minor modifications to the rates in consideration of certain long-term power supply arrangements entered into between AEP and the intervenors. In November 2005, the FERC settlement judge issued a certification of uncontested settlement recommending that the settlement agreement be adopted with minor additional provisions to AEP's tariff to bring such tariff into compliance with existing FERC policy. The settlement certification was accepted by the FERC in January 2006.

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

Management believes that the AEP System is unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows from the FERC's and PJM's market power analysis cannot be determined. Since the cost caps apply only to wholesale loads within AEP's control area inside SPP and these entities are not often in the market for additional power, management does not expect a significant adverse impact from the FERC's actions to-date.

Allocation Agreement between AEP East Companies and AEP West Companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. The current allocation methodology was established at the time of the AEP-CSW merger and, consistent with the terms of the SIA, in November 2005, AEP filed a proposed allocation methodology to be used in 2006 and beyond. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of the AEP West companies. Previously, the SIA allocation provided for a different method of sharing of all such margins between both AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from the one proposed. AEP companies requested that the new methodology be effective on a prospective basis after the FERC's order. The impact on future results of operations and cash flows will depend upon the methodology approved by the FERC, the level of future margins by region and the status of cost recovery mechanisms by state. Total trading and marketing margins are unaffected by the allocation methodology. However, because trading and marketing activities are not treated the same for ratemaking purposes in each state retail jurisdiction and the timing of inclusion of the margins in rates may differ, the AEP East companies' and AEP West companies' results of operations and cash flows could be affected. Management is unable to predict the ultimate effect of this filing on the AEP East companies and AEP West companies' future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

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

	AEGCo			APCo		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 337,544	$ 343,415	Various Periods (a)
Transition Regulatory Assets – Virginia				21,223	25,467	Up to 5 Years (a)
Unamortized Loss on Reacquired Debt	$ 4,258	$ 4,496	20 Years (b)	17,652	18,157	Up to 27 Years (b)
Other	1,314	1,117	Various Periods (a)	80,875	36,368	Various Periods (a)
Total Noncurrent Regulatory Assets	$ 5,572	$ 5,613		$ 457,294	$ 423,407	
Current Regulatory Assets – Under-recovered Fuel Costs – Virginia				$ 30,697	$ -	1 Year (b)
Regulatory Liabilities:						
Asset Removal Costs	$ 27,640	$ 25,428	(d)	$ 86,315	$ 95,763	(d)
Deferred Investment Tax Credits	42,718	46,250	Up to 17 Years (a)	25,723	30,382	Up to 15 Years (c)
SFAS 109 Regulatory Liability, Net	12,331	12,852	Various Periods (a)			
Over-recovery of Fuel Costs – West Virginia				52,399	52,071	(a)
Other				36,793	23,270	Various Periods (a)
Total Noncurrent Regulatory Liabilities	$ 82,689	$ 84,530		$ 201,230	$ 201,486	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	CSPCo			I&M		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 17,723	$ 16,481	Various Periods (a)	$ 118,743	$ 147,167	Various Periods (a)
Transition Regulatory Assets	144,868	156,676	Up to 3 Years (a)			
Other	69,008	38,846	Various Periods (a)	103,943	103,923	Various Periods (b)
Total Noncurrent Regulatory Assets	$ 231,599	$ 212,003		$ 222,686	$ 251,090	
Regulatory Liabilities:						
Asset Removal Costs	$ 117,942	$ 103,104	(c)	$ 280,819	$ 280,054	(c)
Deferred Investment Tax Credits	25,215	27,933	Up to 15 Years (a)	75,077	82,802	Up to 17 Years (a)
Excess ARO for Nuclear Decommissioning				271,318	245,175	(d)
Other	22,187	-	Various Periods (b)	82,801	69,229	Various Periods (b)
Total Noncurrent Regulatory Liabilities	$ 165,344	$ 131,037		$ 710,015	$ 677,260	

(a) Amount does not earn a return.
(b) A portion of the amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant and lowers plant investment reducing overall return.
(d) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, which accrues monthly, and will be paid when the nuclear plant is decommissioned.

	KPCo			OPCo		
	2005	**2004**	**Recovery/ Refund Period**	**2005**	**2004**	**Recovery/ Refund Period**
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 96,578	$ 103,849	Various Periods (a)	$ 159,742	$ 169,866	Various Periods (a)
Transition Regulatory Assets				139,632	225,273	2 years (a)
Other	20,854	14,558	Various Periods (b)	98,633	33,235	Various Periods (b)
Total Noncurrent Regulatory Assets	$ 117,432	$ 118,407		$ 398,007	$ 428,374	
Regulatory Liabilities:						
Asset Removal Costs	$ 30,291	$ 28,232	(c)	$ 110,098	$ 102,875	(c)
Deferred Investment Tax Credits	5,500	6,722	Up to 15 Years (a)	9,416	12,539	Up to 15 Years (a)
Other	21,003	13,040	Various Periods (b)	48,978	-	Various Periods (b)
Total Noncurrent Regulatory Liabilities	$ 56,794	$ 47,994		$ 168,492	$ 115,414	

(a) Amount does not earn a return.
(b) A portion of the amount effectively earns a return.
(c) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	PSO			SWEPCo		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ -	$ -		$ 38,793	$ 18,000	Various Periods (b)
Unrealized Loss on Forward Commitments	18,279	4,730		13,922	4,032	
Unamortized Loss on Reacquired Debt	12,456	14,705	Up to 10 Years (b)	17,973	20,765	Up to 38 Years (b)
Other	19,988	12,516	Various Periods (d)	11,088	12,318	Various Periods (c)
Total Noncurrent Regulatory Assets	$ 50,723	$ 31,951		$ 81,776	$ 55,115	
Current Regulatory Asset - Under-recovered Fuel Costs	$ 108,732	$ 366	1 Year (a)	$ 51,387	$ 4,844	1 Year (a)
Regulatory Liabilities:						
Asset Removal Costs	$ 212,346	$ 220,298	(e)	$ 255,920	$ 249,892	(e)
Deferred Investment Tax Credits	27,273	28,620	Up to 24 Years (d)	31,246	35,539	Up to 12 Years (d)
SFAS 109 Regulatory Liability, Net	12,089	21,963	Various Periods (b)			
Other	32,932	19,676	Various Periods (d)	32,900	24,487	Various Periods (c)
Total Noncurrent Regulatory Liabilities	$ 284,640	$ 290,557		$ 320,066	$ 309,918	

(a) Over/Under-recovered fuel for SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts for SWEPCo do earn a return. PSO fuel balances began earning a return in June 2005.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	TCC			TNC		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 20,616	$ 15,236	Various Periods (a)			
Designated for Securitization	1,435,597	1,361,299	(b)			
Wholesale Capacity Auction True-up	76,464	559,973	(c)			
Refunded Excess Earnings	55,461	-	(c)			
Other	100,649	125,470	Various Periods (e)	$ 9,787	$ 12,023	Various Periods (e)
Total Noncurrent Regulatory Assets	$ 1,688,787	$ 2,061,978		$ 9,787	$ 12,023	
Regulatory Liabilities:						
Asset Removal Costs	$ 231,990	$ 102,624	(f)	$ 82,639	$ 81,143	(f)
Deferred Investment Tax Credits	105,134	107,743	Up to 23 Years (d)	17,427	18,698	Up to 17 Years (d)
Over-recovery of Fuel Costs	177,198	211,526	(c)	4,915	3,920	(c)
Retail Clawback	61,384	61,384	(c)	13,924	13,924	(c)
SFAS 109 Regulatory Liability, Net				6,828	8,500	Various Periods (a)
Other	76,437	76,653	Various Periods (e)	13,999	14,589	Various Periods (e)
Total Noncurrent Regulatory Liabilities	$ 652,143	$ 559,930		$ 139,732	$ 140,774	

(a) Amount earns a return.
(b) Amount includes a carrying cost, was included in TCC's True-up Proceeding and is designated for possible securitization. The cost of the securitization bonds would be recovered over a time period to be determined in a future PUCT proceeding. See "Texas Restructuring" section of Note 6.
(c) See "Texas Restructuring" and "Carrying Costs on Net True-up Regulatory Assets" sections of Note 6 for discussion of carrying costs. Amounts were included in TCC's and TNC's True-up Proceedings for future recovery/refund over a time period to be determined in future PUCT proceedings.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

Texas Restructuring Related Regulatory Assets and Liabilities

Designated for Securitization, Wholesale Capacity Auction True-up and Refunded Excess Earnings regulatory assets and Over-recovery of Fuel Costs and Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations established in Texas for industry restructuring provide for the recovery from ratepayers of these net amounts. See Note 6 for a discussion of our efforts to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of the Cook Plant related outage restart costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to Maintenance and Other Operation Expense under the settlement agreements was $40 million in 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 were amortized as a reduction of revenues. The amortization of amounts deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected I&M's Statement of Income in 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements.

Summary of key provisions of Merger Rate Agreements beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reductions of $221 million over 6 years.
Indiana – I&M	Rate reductions of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the remaining periods of the merger agreements, future results of operations and cash flows could be adversely affected.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of AEP's twelve electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Michigan, Virginia and Texas) in which the AEP electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

TEXAS RESTRUCTURING – Affecting TCC, TNC and SWEPCo

The Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. The PUCT has begun studies to consider further delay of customer choice in the SPP area of Texas. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business operates in SPP.

The Texas Restructuring Legislation provides for True-up Proceedings to determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any excess earnings (net stranded generation costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
- final approved deferred fuel balance, and
- net carrying costs on certain of the above true-up amounts.

In May 2005, TCC filed its True-Up Proceeding seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined that TCC's net true-up regulatory asset was $1.5 billion, which included carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules.

TCC adjusted its December 2005 books to reflect the PUCT's final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded in December 2005 as a pretax extraordinary loss. The difference between the requested amount of $2.4 billion, the approved amount of $1.5 billion and the recorded amount of $1.3 billion at December 31, 2005 is detailed in the table below:

	in millions
True-Up Proceeding Requested Amount	$ 2,406
Wholesale Capacity Auction True-up, including carrying costs	(572)
Commercial Unreasonableness Disallowance	(122)
Return on and of Stranded Costs Disallowance	(159)
Other	(78)
Amount Approved by the PUCT	1,475
Unrecognized but Recoverable Equity Carrying Costs and Other	(200)
Total Recorded Net True-up Regulatory Asset	$ 1,275

The requested $2.4 billion represents what TCC believes it should recover under its interpretation of the provisions of the Texas Restructuring Legislation. However, the $1.3 billion book amount reflects what management believes to be the probable recoverable net regulatory true-up asset at December 31, 2005, taking into account the PUCT's final order in TCC's True-up Proceeding exclusive of various items, principally recoverable but unrecognized equity carrying costs and other items.

Based on the PUCT-approved amount, and carrying costs through the proposed date of securitization, we anticipate requesting to securitize $1.8 billion, as discussed below in the "TCC Securitization Proceeding" section.

The Components of TCC's Net True-up Regulatory Asset as of December 31, 2005 and December 31, 2004 are:

	TCC	
	December 31, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 969	$ 897
Net Generation-related Regulatory Asset	249	249
Excess Earnings	(49)	(10)
Net Stranded Generation Costs Before Carrying Costs	1,169	1,136
Carrying Costs on Stranded Generation Plant Costs	267	225
Net Stranded Generation Costs After Carrying Costs	1,436	1,361
Wholesale Capacity Auction True-up	61	483
Carrying Costs on Wholesale Capacity Auction True-up	16	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(177)	(212)
Net Other Recoverable True-up Amounts	(161)	287
Total Recorded Net True-up Regulatory Asset	$ 1,275	$ 1,648

The majority of the reduction to TCC's net true-up regulatory asset was comprised of two extraordinary adjustments, and the associated nonextraordinary debt carrying costs. The major adjustments were related to TCC's wholesale capacity auction true-up and its stranded plant cost from the sale of its generating plants. The PUCT found that TCC did not comply with the wholesale capacity auction requirements, which resulted in a book reduction of $422 million. Related to the sale of TCC's generation assets, the PUCT determined that TCC acted in a manner that was commercially unreasonable in large part because it failed to determine a minimum price at which it would reject bids for the sale of its generating plants. Based on that determination, TCC reduced its net true-up regulatory asset by $122 million. Other smaller adjustments totaling $7 million were reversed as an extraordinary item.

In addition, the PUCT determined that the purpose of the capacity auction true-up was to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded generation plant cost balance that it determined was included in the capacity auction true-up. Since TCC had previously reduced its book stranded cost regulatory asset by $238 million in 2004 related to the duplicate depreciation, TCC increased its book stranded generation plant cost by $206 million in December 2005. The reduction to debt carrying costs related to all of these adjustments totaled $71 million.

In 2003 and 2004, based upon orders received from the PUCT, TCC recorded provisions to its over-recovered fuel balance resulting in a $209 million over-recovery regulatory liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed as nonextraordinary in the fourth quarter of 2005.

In a future proceeding, certain adjustments for the future cost-of-money benefit of accumulated deferred federal income taxes may be deducted from the recoverable true-up asset, and transferred to a separate regulatory asset to be recovered in normal delivery rates outside of the securitization process which would affect the timing of cash recovery.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. If the PUCT does not make significant changes in response to our request for reconsideration, we expect that TCC will challenge certain of the PUCT's rulings through appeals to Texas state and federal courts. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In TCC's final true-up order, the PUCT reduced net stranded generation costs by $51 million related to the present value of Accumulated Deferred Investment Tax Credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions. Also included in the final true-up order was language whereby the PUCT agreed to consider revisiting this issue if the Internal Revenue Service (IRS) ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. With the agreement in effect, as well as our ability to ultimately appeal the final true-up order, management does not believe a normalization violation has occurred. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table.

The IRS issued proposed regulations in March 2003 that would have liberalized the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS had not issued final regulations, TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. In December 2005, the IRS withdrew these previously proposed regulations and issued new proposed regulations. The new proposed regulations removed the retroactive election that allowed utilities, which were deregulated before March 4, 2003, to pass the benefits of ADITC and EDFIT back to ratepayers. The PUCT computation is premised on the withdrawn proposed regulations and may not be acceptable to the IRS under the new proposed regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of December 31, 2005 and also a loss of the ability to elect accelerated tax depreciation in the future. In light of the new proposed regulations, we are unable to predict how the IRS will ultimately rule on our private letter ruling request. However, prior precedent in this area would lead management to expect the IRS to rule that the PUCT approach of reducing the stranded cost recovery by the present value of its ADITC and EDFIT would, if ultimately imposed by a final, nonappealable order, constitute a normalization violation. Management intends to update the private letter ruling request for the new proposed regulations and issuance of the final order and will continue to work closely with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

Excess Earnings

The Texas Restructuring Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce transmission and distribution capital expenditures. Management believes excess earnings for TNC and SWEPCo are not true-up items. However, in January 2005, intervenors filed testimony in TNC's True-up Proceeding recommending that TNC's excess earnings be increased by approximately $5 million to reflect carrying charges on its excess earnings for the period from January 1, 2002 to March 2005. In addition, intervenors also recommended that TNC's transmission and distribution rates should be reduced by a maximum amount of approximately $3 million on an annual basis related to excess earnings. The PUCT did not address the excess earnings in the final true-up order, and instead required that excess earnings be addressed in TNC's Competition Transition Charge (CTC) filing. TNC's CTC filing was made in August 2005. As noted below, this filing has been suspended until further notice.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduced cash flows over the refund period. Through the end of 2004, TCC had refunded all but $10 million of its excess earnings liability. During 2005, TCC refunded an additional $9 million reducing its unrefunded excess earnings to $1 million. In July 2005, the PUCT approved a preliminary order in TCC's True-up Proceeding that instructed TCC to stop refunding the excess earnings and to offset the remaining balance, which was $1 million, against net stranded generation costs. In the final true-up order, the PUCT has utilized $1 million as a reduction to TCC's net stranded generation costs. However, prior to the final true-up order, in September 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings was unlawful under the Texas Restructuring Legislation. The decision stated that the excess earnings should have been treated as a reduction of stranded costs. As such, in September 2005, TCC recorded a regulatory asset of $56 million (including $7 million of interest) for the future recovery of the $49 million refunded to the REPs and a reduction to net stranded plant regulatory assets of $49 million, which also reduced the amount of carrying costs on TCC's books by $9 million. The PUCT filed a petition with the Texas Supreme Court to review the Texas Court of Appeals' decision. Management is unable to predict the ultimate outcome of these proceedings.

Wholesale Capacity Auction True-up and Stranded Plant Cost

The Texas Restructuring Legislation required that electric utilities and their affiliated power generation companies (PGCs) offer for sale at auction in 2002, 2003 and thereafter, at least 15% of the PGCs' Texas jurisdictional installed generation capacity. According to the legislation, the actual market power prices received in the state-mandated auctions are used to calculate wholesale capacity auction true-up revenues for recovery in the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. Based on its auction prices, TCC recorded a regulatory asset of $483 million in those years. TCC also recorded $126 million of carrying costs related to the wholesale capacity auction true-up, increasing the total asset to $609 million. As noted earlier, the PUCT ruled in the True-up Proceeding that TCC did not comply with the PUCT's rules regarding the auction of 15% of its Texas jurisdictional installed generation capacity. Based upon this ruling, TCC's capacity auction revenues were computed at higher nonauction prices and, as a result, TCC wrote off $422 million of its recorded regulatory asset and $110 million of related carrying costs. At December 31, 2005, TCC has a net true-up recoverable asset related to the wholesale capacity auction true-up of $77 million inclusive of remaining carrying costs.

In a nonaffiliated company's order, the PUCT also reduced that company's requested wholesale capacity auction true-up request. The PUCT determined that the nonaffiliated company had not met the PUCT's rules regarding the auction of 15% of its generation capacity because it failed to sell 15% of its generating capacity. That utility appealed the PUCT's decision to the Texas District Court. The District Court found that the PUCT erred by disallowing a significant portion of that utility's wholesale capacity auction true-up request. Although the facts regarding the nonaffiliated company's wholesale capacity auction true-up request and TCC's wholesale capacity auction true-up request are not exactly the same, management believes the District Court decision is a positive outcome and will prove to be beneficial to TCC's future claim that it is entitled to a significant portion, if not all, of TCC's requested amount.

In addition, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT then determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded plant cost balance that it determined was included in the capacity auction true-up. Since TCC had reduced its booked stranded cost regulatory asset by $238 million in December 2004 related to the duplicate depreciation, TCC increased its stranded plant cost regulatory asset by $206 million effectively adjusting its books to recognize the significantly lower $32 million net disallowance.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to their T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is referred to as the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In December 2003, the PUCT certified that the REPs in the TCC and TNC service territories had reached the 40% threshold for the small commercial class. At December 31, 2005, TCC's recorded retail clawback regulatory liability was $61 million and TNC's was $14 million. TCC recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $61 million, for the retail clawback liability. TNC received payment of $14 million from its nonaffiliated PTB REP in 2005, but has not refunded this money to its customers as of December 31, 2005. TNC's CTC proceeding, the proceeding that will determine the refund methodology, has been suspended. TCC received payment from its nonaffiliated REP in February 2006.

Fuel Balance Recoveries

In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred fuel balance for inclusion in their True-up Proceedings. The PUCT issued final orders in each of these proceedings that resulted in significant disallowances for both companies. Based upon these orders, TCC increased its over-recovered fuel balance by a total of $140 million, which resulted in a $209 million over-recovery liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed in the fourth quarter of 2005. TNC's under-recovered balance was adjusted by a total of $31 million. After the adjustments, TNC's under-recovered balance became an over-recovery of $5 million. Both TCC and TNC have challenged the PUCT's rulings regarding a number of issues in the fuel orders in federal and state court. Intervenors have also challenged certain rulings in the PUCT fuel order in state court.

In September 2005, the Texas District Court in Travis County issued a ruling which upheld the PUCT's decisions in the TNC proceeding. TNC and other parties have filed notice of appeal of that decision. TCC has not received a ruling from the Texas District Court regarding its appeal.

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the favorable federal TNC ruling is applicable to its appeal. The impact of the court order could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the Federal Court system, it could file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT is unsuccessful in its federal court appeal, TCC and TNC can reverse their provisions. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. This is because the ruling may result in a reallocation of off-system sales margins between AEP East companies and AEP West companies. If that occurs, the AEP West companies would receive additional off-system sales margins from the AEP East companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the additional payments from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

In June 2004, the Texas Supreme Court determined that carrying costs should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and ordered that the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling became final.

In a nonaffiliated company's true-up order, the PUCT addressed the Supreme Court's remand decision and specified the manner in which carrying costs should be calculated. Based on this order, TCC first recorded carrying costs in 2004 and continued to accrue carrying costs in 2005. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. As a result, TCC recorded a $27 million reduction in its carrying costs in the first quarter of 2005 and reduced the amount of carrying costs accrued for the remainder of 2005. The PUCT indicated that it will address this retrospective ADFIT cost of money benefit in TCC's securitization proceeding.

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax cost of capital rate from its unbundled cost of service rate proceeding. The embedded debt component of the carrying cost rate is 8.12%. Based on the final order in TCC's True-up Proceeding, TCC reversed, in December 2005, $71 million of carrying costs, resulting in a net $19 million reduction in total carrying costs for 2005. Through December 2005, TCC recorded $283 million of carrying costs ($267 million on stranded generation plant costs and $16 million on wholesale capacity auction true-up). The remaining equity component of $153 million will be recognized in income as collected. TCC will continue to accrue a carrying cost.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% rate of return on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period regarding the rule. TCC received a final order (which is subject to rehearing) in the True-up Proceeding in February 2006. AEP will assert in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order.

The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until a final order is issued in TCC's True-up Proceeding. At that time, carrying costs accrue on the deferred fuel. For the retail clawback, carrying costs accrue when a final order is issued in TCC's True-up Proceeding.

TCC Securitization Proceeding

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge. The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an ADFIT benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of TCC's cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	**$ 1,275**
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	**$ 1,804**

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

The final order did not address the allocation of stranded costs to TCC's wholesale jurisdiction which will be addressed in TCC's securitization proceeding. TCC estimates the amount allocated to wholesale is less than $1 million. However, TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize.

TCC True-up Proceeding Summary

We believe that our recorded net true-up regulatory asset at December 31, 2005 of $1.3 billion accurately reflects the PUCT's final order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no additional impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding. If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

The Components of TNC's True-up Regulatory Liability as of December 31, 2005 and December 31, 2004 are:

	TNC	
	December 31, 2005	**December 31, 2004**
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

TNC completed its True-up Proceeding in 2005 with the PUCT issuing a final order in May 2005. Based upon that final order, TNC adjusted its true-up regulatory liability. TNC filed a CTC proceeding in August 2005 to establish a rate to refund the net true-up regulatory liability. That filing has been suspended until the ruling from TNC's appeal to federal court regarding its final fuel reconciliation is fully resolved. This federal court ruling is discussed above. TNC accrues interest expense on the unrefunded balance and will continue accruing interest expense until the balance is fully refunded.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (Restructuring Act) provided for a Market Development Period (MDP) during which retail customers could choose their electric power suppliers or receive default service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and ended on December 31, 2005. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive default service, which must be offered by the incumbent utility at market rates. As of December 31, 2005, none of OPCo's customers have elected to choose an alternate power supplier and only a modest number of CSPCo's small commercial customers have switched suppliers.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. In February 2004, CSPCo and OPCo (the Ohio companies) filed Rate Stabilization Plans (RSP) with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers.

In January 2005, the PUCO approved the RSP for the Ohio companies. The approved plans provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues for specified costs. CSPCo's cost recovery under the Power Acquisition Rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding (see "Acquisitions" section of Note 10) will diminish CSPCo's potential for the additional annual 4% generation rate increases in 2006 by approximately one-half and to a lesser extent in 2007 and 2008. The plans also provide that the Ohio companies can recover in 2006, 2007 and 2008 environmental carrying costs and PJM-related administrative costs and congestion costs net of firm transmission rights (FTR) revenue from 2004 and 2005 related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $9 million for CSPCo and $47 million for OPCo in 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo related to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. In March 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court which challenged the RSP and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. If the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo's and OPCo's future earnings will be adversely affected. In a nonaffiliated utility's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In addition, if the RSP order were determined on appeal to be illegal under the Restructuring Act, it would have an adverse effect on results of operations, cash flows and possibly financial condition. Although CSPCo and OPCo believe that the RSP plan is legal and intend to defend vigorously the PUCO's order, management cannot predict the ultimate outcome of the pending litigation.

In July 2005, CSPCo and OPCo each filed applications with the PUCO to decrease the transmission rates contained in their retail electric rates in order to reflect the FERC-approved OATT rate. Those applications were supplemented in December 2005 to update the proposed transmission rates to reflect the rates filed as part of a settlement agreement with the FERC (see "RTO Formation/Integration Costs" section of Note 4). As a result, annual transmission rates would be reduced by approximately $12 million and $13 million for CSPCo and OPCo, respectively. In accordance with the Restructuring Act, the Ohio companies also proposed to increase their distribution rates to fully offset the resulting decrease in their transmission rates. The PUCO approved these applications on December 28, 2005 and the new offsetting transmission and distribution rates became effective on that date. Under the terms of the PUCO's order in the RSP, the modified distribution rates in effect on December 31, 2005 are frozen though December 31, 2008 with certain exceptions, including governmentally-imposed changes resulting in increased distribution costs, changes in taxes or for major storm damage service restoration.

In September 2005, the Ohio companies filed with the PUCO to recover through a Transmission Cost Recovery Rider, beginning January 1, 2006, approximately $5 million for CSPCo and $7 million for OPCo of projected 2006 annual net costs incurred as a result of joining PJM. In addition, the Ohio companies requested to practice over/under-recovery deferral accounting for any differences between the revenues collected starting January 1, 2006 and the actual PJM costs incurred. In December 2005, the PUCO issued an order approving the rider components.

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month in which the Wyoming-Jacksons Ferry transmission line enters service in order to reflect their share of costs for that new line. Management anticipates that, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing follows the settlement of our March 2005 filing with the FERC requesting increased OATT rates in which AEP received a three-step increase (see "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4).

The PUCO's order in the RSP requires CSPCo and OPCo to allot a combined total of $14 million of previously provided for unused CSPCo shopping incentives to benefit low-income customers and economic development programs over the three-year period ending December 31, 2008. In a March 2005 rehearing order, the PUCO clarified that the Ohio companies have a regulatory liability of only $14 million of unused shopping incentives. In the second quarter of 2005, CSPCo ceased applying unused shopping incentives to reduce its recoverable transition regulatory asset. Assuming that the $14 million regulatory liability is allocated equally to CSPCo and OPCo, in 2005, CSPCo increased its recoverable transition regulatory asset by $18 million due to the reversal of the unused shopping incentives, transferred $7 million to a regulatory liability and credited the remaining $11 million to pretax earnings and OPCo recorded a regulatory liability of $7 million which it charged to pretax earnings.

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2005, CSPCo incurred $44 million and deferred $21 million and OPCo incurred $46 million and deferred $22 million of such costs for probable future recovery in distribution rates. CSPCo and OPCo have not yet recorded $3 million and $4 million, respectively, of equity carrying costs which are not recognized until collected. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. The Ohio companies believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on the Ohio companies' future results of operations and cash flows.

MICHIGAN RESTRUCTURING – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2005, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2005 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING – Affecting APCo

In April 2004, the Governor of Virginia signed legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the revised restructuring law, APCo is deferring incremental environmental generation costs for future recovery.

ARKANSAS RESTRUCTURING – Affecting SWEPCo

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on SWEPCo's results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the West Virginia Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the West Virginia legislature made tax law changes necessary to preserve the revenues of state and local governments.

In 2001 through 2003, the West Virginia Legislature failed to enact the required tax legislation and the WVPSC closed its dockets. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCo's outside counsel advised that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCo's West Virginia generation business was no longer probable and operations in West Virginia met the requirements to reapply SFAS 71. Reapplying SFAS 71 in West Virginia had an insignificant effect on APCo's 2003 results of operations and financial condition.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned), and Stuart (26% owned) Stations. Similar cases have been filed against other nonaffiliated utilities.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability AEP subsidiaries might have for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If AEP subsidiaries do not prevail, management believes AEP subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If any of the AEP subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In July 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims – Affecting AEP East Companies and West Companies

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions allege that CO_2 emissions from the defendant's power plants constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal has been appealed to the Second Circuit Court of Appeals and briefing continues. Management believes the actions are without merit and intends to defend vigorously against the claims.

Ontario Litigation – Affecting CSPCo and OPCo

In June 2005, CSPCo, OPCo and several nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. AEP has not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_X, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. Management believes CSPCo and OPCo have meritorious defenses to this action and intend to defend vigorously against it.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting AEP System

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2005, APCo and I&M are each named as a Potentially Responsible Party (PRP) for one site and CSPCo and OPCo are each named a PRP for two sites by the Federal EPA. There are seven additional sites for which APCo, CSPCo, I&M, KPCo, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M, OPCo, SWEPCo, TCC and TNC have also been named potentially liable at seven sites under state law. In those instances where we have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, present estimates do not anticipate material cleanup costs for identified sites for which certain Registrant Subsidiaries have been declared PRPs. If significant cleanup costs were attributed to those Registrant Subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in electricity prices.

NUCLEAR – ***Affecting I&M***

Nuclear Plant

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. I&M has a significant future finance commitment to safely dispose of SNF and to decommission and decontaminate the plant. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $41 million which is assessable if the insurer's financial resources would be inadequate to pay for losses.

In 2005, the Price-Anderson Act was extended by amendment through December 31, 2025.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $236 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2005, funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $264 million are in external trust funds.

SNF Litigation

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. The DOE failed to begin accepting SNF by the January 1998 deadline in the law. DOE continues to fail the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, I&M, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability.

The case was tried in March 2004 on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied I&M's pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that I&M may recover post-breach damages in later suits as the costs are incurred.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. After expiration of the licenses, the Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low-level radioactive waste accumulation disposal costs for the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant was $27 million in 2005, 2004 and 2003.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2005 and 2004 and $12 million in 2003 related to special regulatory commission approved funding for decommissioning of the Cook Plant. At December 31, 2005, the total decommissioning trust fund balance for Cook Plant was $870 million. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds, increase or decrease the recorded liability.

Estimates from the decommissioning study could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M will work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, I&M future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The Registrant Subsidiaries have substantial construction commitments to support its operations and environmental investments. The following table shows the estimated construction expenditures by company for 2006:

	(in millions)
AEGCo	$ 14
APCo	943
CSPCo	343
I&M	311
KPCo	100
OPCo	1,070
PSO	279
SWEPCo	288
TCC	278
TNC	73

Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Certain Registrant Subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2017 for APCo, 2015 for CSPCo, 2014 for I&M, 2008 for KPCo, 2021 for OPCo, 2008 for PSO and 2012 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

Potential Uninsured Losses – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility – Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleged that TEM breached the PPA, and sought a determination of its rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA was terminated and (iii) would be pursuing against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus pre-judgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. OPCo asked the court to modify the judgment to (i) award a termination payment to OPCo under the terms of the PPA; (ii) grant OPCo's attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted AEP's motion for reconsideration concerning TEM's parent guaranty and increased AEP's judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found to be unenforceable by the court ultimately deciding the case, OPCo could be adversely affected to the extent OPCo is unable to find other purchasers of the power with similar contractual terms and to the extent claimed termination value damages are not fully recovered from TEM.

Merger Litigation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Upon repeal of PUHCA on February 8, 2006, the SEC dismissed the proceeding challenging AEP's merger with CSW.

Texas Commercial Energy, LLP Lawsuit – Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four of its subsidiaries, including TCC and TNC, ERCOT and a number of nonaffiliated energy companies. The action alleged violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleged that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced TCE into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleged over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. The Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision and the appellate court affirmed the lower court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court, which was denied in January 2006. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. In December 2005, the federal court dismissed the plaintiffs' federal claims with prejudice and dismissed their state law claims without prejudice. After that decision, AEP and its subsidiaries settled all claims with plaintiffs in a settlement, subject to a confidentiality clause, and without material impact on results of operations or financial condition.

Coal Transportation Dispute – Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in 2004 and 2005. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate. BNSF contends that it was underpaid approximately $9.5 million, including interest. This matter was submitted to an arbitration panel in January 2006.

FERC Long-term Contracts – Affecting AEP East Companies and AEP West Companies

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

8. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At December 31, 2005, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, each with a maturity of March 2006.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $53 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

Effective July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine. After consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses.

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant Subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2005, 2004 and 2003, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except for TCC. TCC sales agreements include indemnifications with a maximum exposure of $443 million related to the sale price of its generation assets. See "Texas Plants – TCC and TNC Generation Assets" section of Note 10. There are no material liabilities recorded for any indemnifications.

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

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2005, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 6
CSPCo	3
I&M	4
KPCo	2
OPCo	5
PSO	5
SWEPCo	5
TCC	6
TNC	3

9. COMPANY-WIDE STAFFING AND BUDGET REVIEW

The following table shows the severance benefits expense recorded in 2005 (primarily in Other Operation) resulting from a company-wide staffing and budget review, including the allocation of approximately $19 million of severance benefits expense associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees, but receives allocated expenses. Remaining accruals, reflected primarily in Current Liabilities – Other, range from $8 thousand to $1.1 million as of December 31, 2005, and are expected to be settled by the end of the second quarter of 2006.

Company	Year Ended December 31, 2005 (in millions)
AEGCo	$ 0.3
APCo	4.5
CSPCo	2.6
I&M	4.7
KPCo	1.1
OPCo	3.9
PSO	1.4
SWEPCo	1.8
TCC	4.3
TNC	1.3

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND OTHER LOSSES

ACQUISITIONS

2005

Waterford Plant - Affecting CSPCo

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company - Affecting CSPCo

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, AEP agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of its customers over approximately 5 years. Also included in the proposed transaction is a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station - Affecting APCo

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia. This transaction was completed in December 2005 for $100 million.

DISPOSITIONS

2005

Texas Plants – South Texas Project - Affecting TCC

In February 2004, TCC signed an agreement to sell its 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, TCC entered into sales agreements with two of its nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on TCC's results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System, which included all of the generation facilities owned by the Registrant Subsidiaries. TCC's assets and liabilities related to STP were classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in its Consolidated Balance Sheet as of December 31, 2004.

2004

Texas Plants – TCC and TNC Generation Assets

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability-must-run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel an RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, TNC recorded a pretax write-down of utility assets of approximately $34 million in 2002. The decision to deactivate the TCC plants resulted in a pretax write-down of utility assets of approximately $96 million, which was deferred and recorded in regulatory assets in 2002.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional pretax asset impairment charge of $4 million in the fourth quarter of 2002. In addition, TNC recorded related inventory write-downs of $3 million. Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in regulatory assets in 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in regulatory assets.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability-must-run" status.

During 2003, after receiving indicative bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets. In accordance with the Texas Restructuring Legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which was expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding (see "Texas Restructuring" section of Note 6).

In March 2004, TCC signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on TCC's 2004 results of operations.

The remaining generation assets and liabilities of TCC are classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, on TCC's Consolidated Balance Sheets. See "Assets Held for Sale" section of this note for additional information.

2003

Water Heater Assets – Affecting APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. AEP sold its water heater rental program and recorded a pretax loss in the first quarter of 2003 based upon final terms of the sale agreement. AEP provided for pretax charges in the fourth quarter of 2002 based on an estimated sales price. See below for amounts of the loss by company:

Subsidiary Company	Loss on Sale Recorded in 2003 (Pretax)
	(in thousands)
APCo	$ 56
CSPCo	740
I&M	787
KPCo	11
OPCo	2,165

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station-Affecting TCC

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By May 2004, TCC received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of its nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in Dallas County, Texas State District Court by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that one co-owner exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party requested that the court declare the co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of the unrelated party on October 10, 2005. TCC and the other nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. A decision by the Appeals Court is expected during the first half of 2006. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, on TCC's Consolidated Balance Sheets at December 31, 2005 and 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by the Registrant Subsidiaries.

The assets and liabilities of the entities held for sale at December 31, 2005 and 2004 are as follows:

	As of December 31,	
Texas Plants (TCC)	**2005**	**2004**
Assets:	**(in millions)**	
Other Current Assets	$ 1	$ 24
Property, Plant and Equipment, Net	43	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale - Texas Generation Plants	$ 44	$ 628
Liabilities:		
Regulatory Liabilities	$ -	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale - Texas Generation Plants	$ -	$ 250

OTHER LOSSES

2005

Conesville Units 1 and 2 – Affecting CSPCo

In the third quarter of 2005, following an extensive review of the commercial viability of CSPCo's Conesville units 1 and 2, CSPCo committed to a plan to retire these units before the end of their previously estimated useful lives. As a result, Conesville units 1 and 2 were considered retired as of the third quarter of 2005.

A pretax charge of approximately $39 million was recognized in 2005 related to CSPCo's decision to retire the units. The impairment amount is classified as Asset Impairments and Other Related Charges in CSPCo's 2005 Consolidated Statement of Income.

2003

Blackhawk Coal Company – Affecting I&M

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased operations due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a pretax charge of $10 million was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Assets Impairments in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and life insurance benefits for retired employees. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004. The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result of implementing FSP FAS 106-2, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

The following table provides the reduction in the net periodic postretirement cost for 2004 for the Registrant Subsidiaries:

	Postretirement Benefit Cost Reduction (in thousands)
APCo	$ 5,208
CSPCo	2,417
I&M	3,647
KPCo	690
OPCo	4,106
PSO	1,520
SWEPCo	1,571
TCC	1,849
TNC	770

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2005, and a statement of the funded status as of December 31 for both years:

Pension Obligations, Plan Assets, Funded Status as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Service Cost	93	86	42	41
Interest Cost	228	228	107	117
Participant Contributions	-	-	20	18
Actuarial (Gain) Loss	191	379	(320)	(130)
Benefit Payments	(273)	(273)	(118)	(109)
Projected Obligation at December 31	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,555	$ 3,180	$ 1,093	$ 950
Actual Return on Plan Assets	224	409	70	98
Company Contributions	637	239	107	136
Participant Contributions	-	-	20	18
Benefit Payments	(273)	(273)	(118)	(109)
Fair Value of Plan Assets at December 31	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Funded Status:				
Funded Status at December 31	$ (204)	$ (553)	$ (659)	$ (1,007)
Unrecognized Net Transition Obligation	-	-	152	179
Unrecognized Prior Service Cost (Benefit)	(9)	(9)	5	5
Unrecognized Net Actuarial Loss	1,266	1,040	471	795
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

Amounts Recognized in the Balance Sheets as of December 31, 2005 and 2004

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Prepaid Benefit Costs	$ 1,099	$ 524	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(31)	(28)
Additional Minimum Liability	(35)	(566)	N/A	N/A
Intangible Asset	6	36	N/A	N/A
Pretax Accumulated Other Comprehensive Income	29	530	N/A	N/A
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

N/A = Not Applicable

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category	(in percentages)		
Equity Securities	70	66	68
Debt Securities	28	25	25
Cash and Cash Equivalents	2	9	7
Total	100	100	100

The asset allocations for AEP's other postretirement benefit plans at the end of 2005 and 2004, and target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category	(in percentages)		
Equity Securities	66	68	70
Debt Securities	31	30	28
Other	3	2	2
Total	100	100	100

AEP's investment strategy for their employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate. Because of the $320 million and $200 million contributions at the end of 2005 and 2004, respectively, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006 and 2005.

The value of AEP's pension plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The qualified plans paid $263 million in benefits to plan participants during 2004 (nonqualified plans paid $10 million in benefits).

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

	2005	2004
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,053	$ 3,918
Nonqualified Pension Plans	81	80
Total	$ 4,134	$ 3,998

Minimum Pension Liability

AEP's combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $204 million and $553 million at December 31, 2005 and December 31, 2004, respectively. For AEP's underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2005 and 2004 were as follows:

	Underfunded Pension Plans As of December 31,	
	2005	2004
	(in millions)	
Projected Benefit Obligation	$ 84	$ 2,978
Accumulated Benefit Obligation	81	2,880
Fair Value of Plan Assets	-	2,406
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	81	474

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

AEP made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet its goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in percentages)			
Discount Rate	5.50	5.50	5.65	5.80
Rate of Compensation Increase	5.90(a)	3.70	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The method used to determine the discount rate that AEP utilizes for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, AEP changed to a duration-based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2005 and 2004 under this method was 5.50% for pension plans and 5.65% and 5.80%, respectively, for other postretirement benefit plans.

For 2005, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

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

Employer Contributions	Pension Plans 2006	Pension Plans 2005	Other Postretirement Benefit Plans 2006	Other Postretirement Benefit Plans 2005
		(in millions)		
Required Contributions (a)	$ 8	$ 10	N/A	N/A
Additional Discretionary Contributions	-	$ 626 (b)	$ 96	$ 107

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

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

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

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2006	$ 291	$ 117	$ (9)
2007	305	125	(10)
2008	316	133	(10)
2009	335	140	(11)
2010	344	148	(11)
Years 2011 to 2015, in Total	1,811	857	(65)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
			(in millions)			
Service Cost	$ 93	$ 86	$ 80	$ 42	$ 41	$ 42
Interest Cost	228	228	233	107	117	130
Expected Return on Plan Assets	(314)	(292)	(318)	(92)	(81)	(64)
Amortization of Transition (Asset) Obligation	-	2	(8)	27	28	28
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	55	17	11	25	36	52
Net Periodic Benefit Cost (Credit)	61	40	(3)	109	141	188
Capitalized Portion	(17)	(10)	(3)	(33)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 44	$ 30	$ (6)	$ 76	$ 95	$ 145

Net Pension Cost by Registrant

The following table provides the net periodic benefit cost (credit) for the plans by the following Registrant Subsidiaries for fiscal years 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
			(in thousands)			
APCo	$ 7,391	$ 1,272	$ (5,202)	$ 20,005	$ 25,847	$ 33,747
CSPCo	2,143	(1,626)	(5,399)	8,202	11,050	14,684
I&M	9,463	4,460	(812)	13,524	17,259	22,999
KPCo	1,506	571	(566)	2,204	2,961	4,043
OPCo	4,825	(415)	(6,251)	15,442	20,975	28,143
PSO	295	2,795	(291)	6,989	8,449	9,885
SWEPCo	1,462	3,602	1,018	6,849	8,400	10,264
TCC	(880)	2,987	(123)	7,521	10,144	12,951
TNC	158	1,351	606	3,291	4,280	5,875

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
			(in percentages)			
Discount Rate	5.50	6.25	6.75	5.80	6.25	6.75
Expected Return on Plan Assets	8.75	8.75	9.00	8.37	8.35	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2005 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was to 8.75% for 2005. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was increased to 8.37%.

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

Health Care Trend Rates	2005	2004
Initial	9.00 %	10.0 %
Ultimate	5.00 %	5.0 %
Year Ultimate Reached	2009	2009

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	263	(215)

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The contributions to the plan are 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following Registrant Subsidiaries for fiscal years 2005, 2004 and 2003:

	2005	2004	2003
		(in thousands)	
APCo	$ 6,780	$ 6,538	$ 6,450
CSPCo	2,929	2,723	2,745
I&M	7,892	7,262	7,616
KPCo	1,166	1,030	1,042
OPCo	5,962	5,688	5,719
PSO	2,915	2,731	2,350
SWEPCo	3,935	3,571	3,418
TCC	2,452	2,544	2,757
TNC	1,022	1,126	1,332

12. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business except AEGCo, which is an electricity generation business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

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

Registrant Subsidiaries' accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized on the accrual or settlement basis.

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

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

Fair Value Hedging Strategies

Certain Registrant Subsidiaries enter into interest rate swap transactions in order to manage interest rate risk exposure. The interest rate swap transactions effectively modify exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant Subsidiaries record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged in Interest Expense. During 2005, 2004 and 2003, no Registrant Subsidiaries recognized hedge ineffectiveness related to these swaps.

Cash Flow Hedging Strategies

Certain Registrant Subsidiaries may enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against foreign currencies, the decline in value of future foreign currency cash flows is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. The impact of these hedges, which is immaterial, is included in Operating Expenses.

Certain Registrant Subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. Certain Registrant Subsidiaries enter into forward starting interest rate swap or treasury lock contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. Registrant Subsidiaries reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. During 2005 and 2003, certain Registrant Subsidiaries reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, certain Registrant Subsidiaries reclassified immaterial amounts to earnings because the original forecasted transaction did not occur within the originally specified time period.

Registrant Subsidiaries enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative contracts to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2005, 2004 and 2003, certain Registrant Subsidiaries recognized immaterial amounts in earnings related to hedge ineffectiveness.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2003, 2004 and 2005:

	(in thousands)
APCo	
Balance at December 31, 2002	$ (1,920)
Effective portion of changes in fair value	(448)
Reclasses from AOCI to net income	799
Balance at December 31, 2003	(1,569)
Effective portion of changes in fair value	(6,269)
Reclasses from AOCI to net income	(1,486)
Balance at December 31, 2004	(9,324)
Effective portion of changes in fair value	(4,515)
Reclasses from AOCI to net income	(2,582)
Ending Balance, December 31, 2005	$ (16,421)
CSPCo	
Balance at December 31, 2002	$ (267)
Effective portion of changes in fair value	194
Reclasses from AOCI to net income	275
Balance at December 31, 2003	202
Effective portion of changes in fair value	2,304
Reclasses from AOCI to net income	(1,113)
Balance at December 31, 2004	1,393
Effective portion of changes in fair value	(71)
Reclasses from AOCI to net income	(2,181)
Ending Balance, December 31, 2005	$ (859)

I&M		
Balance at December 31, 2002	$	(286)
Effective portion of changes in fair value		209
Reclasses from AOCI to net income		299
Balance at December 31, 2003		222
Effective portion of changes in fair value		(3,141)
Reclasses from AOCI to net income		(1,157)
Balance at December 31, 2004		(4,076)
Effective portion of changes in fair value		2,489
Reclasses from AOCI to net income		(1,880)
Ending Balance, December 31, 2005	$	(3,467)
KPCo		
Balance at December 31, 2002	$	322
Effective portion of changes in fair value		75
Reclasses from AOCI to net income		23
Balance at December 31, 2003		420
Effective portion of changes in fair value		918
Reclasses from AOCI to net income		(525)
Balance at December 31, 2004		813
Effective portion of changes in fair value		81
Reclasses from AOCI to net income		(1,088)
Ending Balance, December 31, 2005	$	(194)
OPCo		
Balance at December 31, 2002	$	(738)
Effective portion of changes in fair value		256
Reclasses from AOCI to net income		379
Balance at December 31, 2003		(103)
Effective portion of changes in fair value		2,830
Reclasses from AOCI to net income		(1,486)
Balance at December 31, 2004		1,241
Effective portion of changes in fair value		2,281
Reclasses from AOCI to net income		(2,767)
Ending Balance, December 31, 2005	$	755
PSO		
Balance at December 31, 2002	$	(42)
Effective portion of changes in fair value		18
Reclasses from AOCI to net income		180
Balance at December 31, 2003		156
Effective portion of changes in fair value		713
Reclasses from AOCI to net income		(469)
Balance at December 31, 2004		400
Effective portion of changes in fair value		(1,168)
Reclasses from AOCI to net income		(344)
Ending Balance, December 31, 2005	$	(1,112)
SWEPCo		
Balance at December 31, 2002	$	(48)
Effective portion of changes in fair value		21
Reclasses from AOCI to net income		211
Balance at December 31, 2003		184
Effective portion of changes in fair value		(450)
Reclasses from AOCI to net income		(554)
Balance at December 31, 2004		(820)
Effective portion of changes in fair value		(4,817)
Reclasses from AOCI to net income		(215)
Ending Balance, December 31, 2005	$	(5,852)

TCC	
Balance at December 31, 2002	$ (36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	139
Balance at December 31, 2003	(1,828)
Effective portion of changes in fair value	866
Reclasses from AOCI to net income	1,619
Balance at December 31, 2004	657
Effective portion of changes in fair value	(635)
Reclasses from AOCI to net income	(246)
Ending Balance, December 31, 2005	$ (224)

TNC	
Balance at December 31, 2002	$ (15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	55
Balance at December 31, 2003	(601)
Effective portion of changes in fair value	373
Reclasses from AOCI to net income	513
Balance at December 31, 2004	285
Effective portion of changes in fair value	(290)
Reclasses from AOCI to net income	(106)
Ending Balance, December 31, 2005	$ (111)

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2005 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is twelve months.

	(in thousands)
APCo	$ 3,414
CSPCo	713
I&M	1,050
KPCo	207
OPCo	(332)
PSO	632
SWEPCo	1,150
TCC	186
TNC	93

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of significant financial instruments for Registrant Subsidiaries at December 31, 2005 and 2004 are summarized in the following tables.

	2005		2004	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
AEGCo				
Long-term Debt	$ 44,828	$ 45,216	$ 44,820	$ 46,249
APCo				
Long-term Debt	2,151,378	2,134,973	1,784,598	1,822,687
CSPCo				
Long-term Debt	1,196,920	1,232,553	987,626	1,040,885
I&M				
Long-term Debt	1,444,940	1,456,000	1,312,843	1,349,614
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	61,445	61,637
KPCo				
Long-term Debt	486,990	484,834	508,310	521,776
OPCo				
Long-term Debt	2,199,670	2,250,708	2,011,060	2,092,645
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	5,000	5,016
PSO				
Long-term Debt	571,071	568,998	546,092	557,630
SWEPCo				
Long-term Debt	746,035	744,915	805,369	833,246
TCC				
Long-term Debt	1,853,496	1,916,511	1,907,294	2,013,546
TNC				
Long-term Debt	276,845	281,047	314,357	329,514

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNF disposal for I&M. I&M reports trusts in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on its Consolidated Balance Sheets. In 2004, TCC reported trusts in Assets Held for Sale – Texas Generation Plant on its Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M		TCC	
	2005	2004	2005	2004
	(in thousands)			
Fair Value	$ 1,133,600	$ 1,053,400	$ -	$ 143,200
Cost Basis	988,500	936,500	-	107,000

	I&M			TCC		
	2005	2004	2003	2005	2004	2003
	(in thousands)					
Net Unrealized Gain (Loss)	$ 28,200	$ 34,500	$ 35,500	$ -	$ 6,400	$ 16,700

14. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes before extraordinary loss and cumulative effect of accounting changes as reported are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2005					
Income Tax Expense (Credit)					
Current	$ 5,089	$ (1,915)	$ 44,968	$ 62,082	$ 2,803
Deferred	(1,666)	72,763	19,209	26,873	10,555
Deferred Investment Tax Credits	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
Total Income Tax as Reported	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2005					
Income Tax Expense (Credit)					
Current	$ 68,508	$ (14,510)	$ 44,156	$ 106,437	$ 24,426
Deferred	59,593	46,342	(4,942)	(91,387)	(4,578)
Deferred Investment Tax Credits	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
Total Income Tax as Reported	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2004					
Income Tax Expense (Credit)					
Current	$ 5,442	$ 37,689	$ 57,140	$ 84,639	$ (2,870)
Deferred	(2,219)	47,585	13,395	(5,548)	12,774
Deferred Investment Tax Credits	(3,339)	(163)	(2,864)	(7,476)	(1,233)
Total Income Tax as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2004					
Income Tax Expense (Credit)					
Current	$ 75,883	$ (12,434)	$ 26,271	$ 123,304	$ 19,565
Deferred	23,329	22,034	12,782	16,490	4,236
Deferred Investment Tax Credits	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
Total Income Tax as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509

Year Ended December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Income Tax Expense (Credit)					
Current	$ 7,285	$ 83,803	$ 81,286	$ 63,473	$ (9,222)
Deferred	(5,838)	24,563	(4,514)	(14,894)	20,107
Deferred Investment Tax Credits	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
Total Income Tax as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Income Tax Expense (Credit)					
Current	$ 117,024	$ 54,268	$ 45,456	$ 90,986	$ 35,276
Deferred	24,482	(14,641)	9,942	19,393	(3,493)
Deferred Investment Tax Credits	(3,107)	(1,790)	(4,326)	(5,207)	(1,520)
Total Income Tax as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263

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

Year Ended December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$ 8,695	$ 133,576	$ 136,960	$ 146,852	$ 20,809
Cumulative Effect of Accounting Changes	-	2,256	839	-	-
Income Taxes	(109)	66,189	61,460	81,230	12,136
Pretax Income	$ 8,586	$ 202,021	$ 199,259	$ 228,082	$ 32,945
Income Tax on Pretax Income at Statutory Rate (35%)	$ 3,005	$ 70,707	$ 69,741	$ 79,829	$ 11,531
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	757	11,257	1,614	19,492	1,644
Nuclear Fuel Disposal Costs	-	-	-	(3,413)	-
Allowance for Funds Used During Construction	(1,097)	(4,786)	(679)	(3,819)	(614)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(4,275)	(357)	(5,476)	(995)
Investment Tax Credits (net)	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
State and Local Income Taxes	723	2,223	448	6,598	778
Other	(339)	(4,278)	(6,590)	(4,653)	1,014
Total Income Taxes as Reported	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136
Effective Income Tax Rate	N.M.	32.8%	30.8%	35.6%	36.8%

N.M. = Not Meaningful

	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Year Ended December 31, 2005					
Net Income (Loss)	$ 245,844	$ 57,893	$ 73,938	$ (173,779)	$ 33,004
Extraordinary Loss	-	-	-	224,551	-
Cumulative Effect of Accounting Changes	4,575	-	1,252	-	8,472
Income Taxes	124,978	30,485	34,922	12,441	18,577
Pretax Income	$ 375,397	$ 88,378	$ 110,112	$ 63,213	$ 60,053
Income Tax on Pretax Income at Statutory Rate (35%)	$ 131,389	$ 30,932	$ 38,539	$ 22,125	$ 21,019
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	5,201	(775)	(211)	(519)	(513)
Depletion	-	-	(3,150)	-	-
Investment Tax Credits (net)	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
State and Local Income Taxes	(5,437)	(1,387)	1,831	300	718
Other	(3,052)	3,062	2,205	(6,856)*	(1,376)
Total Income Taxes as Reported	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577
Effective Income Tax Rate	33.3%	34.5%	31.7%	19.7%	30.9%

*Includes $(3,900) of consolidated tax savings from parent.

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2004					
Net Income	$ 7,842	$ 153,115	$ 140,258	$ 133,222	$ 25,905
Income Taxes	(116)	85,111	67,671	71,615	8,671
Pretax Income	$ 7,726	$ 238,226	$ 207,929	$ 204,837	$ 34,576
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,704	$ 83,379	$ 72,775	$ 71,693	$ 12,102
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	808	10,719	2,570	19,023	1,466
Nuclear Fuel Disposal Costs	-	-	-	(3,338)	-
Allowance for Funds Used During Construction	(1,060)	(3,948)	(515)	(3,160)	(603)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(1,632)	(336)	(2,974)	(1,497)
Investment Tax Credits (net)	(3,339)	(163)	(2,864)	(7,476)	(1,233)
State and Local Income Taxes	933	6,629	159	7,102	(197)
Other	(536)	(9,873)	(4,118)	(9,652)	(1,367)
Total Income Taxes as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671
Effective Income Tax Rate	N.M.	35.7%	32.5%	35.0%	25.1%

N.M. = Not Meaningful

Year Ended December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income	$ 210,116	$ 37,542	$ 89,457	$ 174,122	$ 47,659
Extraordinary Loss	-	-	-	120,534	-
Income Taxes	96,110	7,809	34,727	135,058	22,509
Pretax Income	$ 306,226	$ 45,351	$ 124,184	$ 429,714	$ 70,168
Income Tax on Pretax Income at Statutory Rate (35%)	$ 107,179	$ 15,873	$ 43,464	$ 150,400	$ 24,559
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,977	(937)	(1,622)	(812)	(739)
Depletion	-	-	(2,100)	-	-
Investment Tax Credits (net)	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
State and Local Income Taxes	305	1,882	4,736	543	2,762
Other	(13,249)	(7,218)	(5,425)	(10,337)	(2,781)
Total Income Taxes as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509
Effective Income Tax Rate	31.4%	17.2%	28.0%	31.4%	32.1%

Year Ended December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$ 7,964	$ 280,040	$ 200,430	$ 86,388	$ 32,330
Cumulative Effect of Accounting Changes	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pretax Income	$ 6,057	$ 308,003	$ 246,809	$ 130,696	$ 43,139
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,120	$ 107,801	$ 86,383	$ 45,744	$ 15,099
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	371	9,209	2,220	17,735	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State and Local Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,439)	(8,518)	(8,646)	(4,108)
Total Income Taxes as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%

N.M. = Not Meaningful

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income	$ 375,663	$ 53,891	$ 98,141	$ 217,669	$ 58,557
Cumulative Effect of Accounting Changes	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pretax Income	$ 389,430	$ 91,728	$ 140,696	$ 322,719	$ 85,926
Income Tax on Pretax Income at Statutory Rate (35%)	$ 136,301	$ 32,105	$ 49,244	$ 112,952	$ 30,074
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,096	(467)	(390)	(957)	(214)
Depletion	-	-	(2,100)	-	-
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State and Local Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,608)	5,104	(1,079)	8,818	(1,154)
Total Income Taxes as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

As of December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Deferred Tax Assets	$ 61,315	$ 221,910	$ 76,785	$ 614,838	$ 26,806
Deferred Tax Liabilities	(84,932)	(1,174,407)	(575,017)	(950,102)	(261,525)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)
Property Related Temporary Differences	$ (56,297)	$ (695,698)	$ (391,117)	$ (42,401)	$ (175,512)
Amounts Due From Customers For Future Federal Income Taxes	5,711	(93,171)	(6,053)	(28,714)	(24,720)
Deferred State Income Taxes	(3,987)	(108,455)	(9,409)	(36,352)	(25,950)
Transition Regulatory Assets	-	(7,428)	(50,719)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	8,944	473	1,922	120
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	32,018	-	-	21,303	-
Accrued Nuclear Decommissioning Expense	-	-	-	(214,126)	-
Deferred Fuel and Purchased Power	-	7,471	(39)	(1,200)	-
Deferred Cook Plant Restart Costs	-	-	-	-	-
Accrued Pensions	-	(48,649)	(40,460)	(28,443)	(6,488)
Nuclear Fuel	-	-	-	(8,040)	-
All Other (Net)	(1,062)	(15,511)	(908)	787	(2,169)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)

As of December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Deferred Tax Assets	$ 138,836	$ 50,570	$ 67,226	$ 146,877	$ 37,158
Deferred Tax Liabilities	(1,126,222)	(486,952)	(476,739)	(1,195,249)	(169,493)
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)
Property Related Temporary Differences	$ (789,885)	$ (336,743)	$ (321,810)	$ (240,361)	$ (121,192)
Amounts Due From Customers For Future Federal Income Taxes	(51,780)	4,231	(961)	7,216	3,892
Deferred State Income Taxes	(41,366)	(59,574)	(45,218)	(43,427)	(7,316)
Transition Regulatory Assets	(49,505)	-	14	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,983)	-
Nuclear Fuel	-	-	-	-	-
Deferred Income Taxes on Other Comprehensive Loss	(406)	681	3,300	620	271
Deferred Fuel and Purchased Power	-	(37,984)	(26,449)	(1,738)	(8,554)
Accrued Pensions	(52,450)	(32,387)	(29,041)	(41,894)	(17,698)
Provision for Refund	-	67	843	40,111	11,671
Regulatory Assets	7,340	-	(496)	(464,080)	(2,915)
Securitized Transition Assets	-	-	-	(231,587)	-
All Other (Net)	(9,334)	25,327	10,305	(3,173)	9,506
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)

As of December 31, 2004	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Deferred Tax Assets	$ 65,740	$ 238,784	$ 98,848	$ 650,596	$ 39,511
Deferred Tax Liabilities	(90,502)	(1,091,320)	(563,393)	(966,326)	(267,047)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)
Property Related Temporary Differences	$ (58,895)	$ (680,324)	$ (385,426)	$ (71,771)	$ (169,452)
Amounts Due From Customers For Future Federal Income Taxes	6,266	(94,438)	(5,652)	(34,260)	(25,112)
Deferred State Income Taxes	(5,050)	(106,817)	(25,658)	(48,830)	(32,099)
Transition Regulatory Assets	-	(8,914)	(54,852)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	43,978	32,747	24,366	4,725
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	33,967	-	-	22,600	-
Accrued Nuclear Decommissioning Expense	-	-	-	(188,428)	-
Deferred Fuel and Purchased Power	-	20,245	(39)	(19)	-
Accrued Pensions	-	(8,306)	(12,528)	6,135	(768)
Nuclear Fuel	-	-	-	(15,485)	-
All Other (Net)	(1,050)	(17,960)	(13,137)	(10,038)	(4,830)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)

As of Ended December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Deferred Tax Assets	$ 165,891	$ 76,411	$ 70,039	$ 248,456	$ 33,063
Deferred Tax Liabilities	(1,109,356)	(460,501)	(469,795)	(1,495,567)	(171,528)
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)
Property Related Temporary Differences	$ (781,479)	$ (323,357)	$ (329,073)	$ (386,287)	$ (126,359)
Amounts Due From Customers For Future Federal Income Taxes	(55,121)	7,687	5,927	7,513	4,552
Deferred State Income Taxes	(78,060)	(59,598)	(44,074)	(42,693)	(7,705)
Transition Regulatory Assets	(79,480)	-	(153)	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,853)	-
Deferred Income Taxes on Other Comprehensive Loss	39,989	(40)	635	188	69
Deferred Fuel and Purchased Power	-	(126)	(10,274)	(1,738)	(8,554)
Accrued Pensions	(7,963)	(30,463)	(26,219)	(38,836)	(16,432)
Provision for Refund	-	67	1,915	51,838	11,513
Deferred Book Gain	-	-	-	71,749	-
Regulatory Assets	-	-	(581)	(580,736)	2,886
Securitized Transition Assets	-	-	-	(257,612)	-
All Other (Net)	18,649	21,740	2,141	(568)	1,565
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, 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 IRS and other taxing authorities routinely examine the Registrant Subsidiaries tax returns. Management believes that the Registrant Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. These positions relate to the timing and amount of income, deductions and the computation of the tax liability. Registrant Subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries have received Revenue Agent's Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. CSW, which was a separate consolidated group prior to its merger with AEP, is currently being audited for the years 1997 through the date of the merger in June 2000. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2005, Registrant Subsidiaries have total provisions for uncertain tax positions of approximately $28 million, excluding AEGCo. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

On October 22, 2004, the American Jobs Creation Act of 2004 (Act) was signed into law. The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9% (when fully phased-in in 2010) on a percentage of "qualified production activities income." For 2005 and for 2006, the deduction is 3% of qualified production activities income. The deduction increases to 6% for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. The FERC has issued an order that states the deduction is a special deduction that reduces the amount of income taxes due from energy sales. While the U.S. Treasury has issued proposed regulations on the calculation of the deduction, these proposed regulations lack clarity as to determination of qualified production activities income as it relates to utility operations. Management believes that the special deduction for 2006 will not materially affect our results of operations, cash flows, or financial condition.

On August 8, 2005 the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of Integrated Gasification Combined Cycle (IGCC) plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP has announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. The United States Treasury Department was to announce by February 6, 2006 the program whereby taxpayers could apply for and be allocated these credits. The Treasury Department has yet to define its program. Management cannot predict if AEP will be allocated any of these tax credits.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over 84-months in lieu of taking a depreciation deduction over 20-years. This act also allows for the transfer ("poured-over") of funds held in non-qualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the non-qualified funds are poured-over; the funds are poured-over over the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for non-qualified funds. Management believes that the tax law changes discussed in this paragraph will not materially affect our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. Management believes that the application of these tax acts will not materially affect our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows in thousands:

Company	Other Regulatory Liabilities (a)	SFAS 109 Regulatory Asset, Net (b)	State Income Tax Expense (c)	Deferred State Income Tax Liabilities (d)
APCo	$ -	$ 10,945	$ 2,769	$ 13,714
CSPCo	15,104	-	-	15,104
I&M	-	5,195	-	5,195
KPCo	-	3,648	-	3,648
OPCo	41,864	-	-	41,864
PSO	-	-	706	706
SWEPCo	-	582	119	701
TCC	-	1,156	365	1,521
TNC	-	120	75	195

(a) The reversal of deferred state income taxes for the Ohio companies was recorded as a regulatory liability pending rate-making treatment in Ohio.
(b) Deferred state income tax adjustments related to those companies in which state income taxes flow through for rate-making purposes reduced the regulatory asset associated with the deferred state income tax liabilities.
(c) These amounts were recorded as a reduction to Income Tax Expense.
(d) Total deferred state income tax liabilities that reversed during 2005 related to Ohio law change.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 was approximately $1 million and $1 million for CSPCo and OPCo, respectively.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance polices; all of which will not have a material impact on future results of operations and cash flows.

15. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Maintenance and Other Operation expense in accordance with rate-making treatment for regulated operations. Capital leases for Nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Lease Payments on Operating Leases	$ 77,872	$ 8,539	$ 6,194	$ 97,700	$ 1,735
Amortization of Capital Leases	284	6,273	3,313	6,681	1,519
Interest on Capital Leases	709	449	540	2,442	34
Total Lease Rental Costs	$ 78,865	$ 15,261	$ 10,047	$ 106,823	$ 3,288

Year Ended December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Lease Payments on Operating Leases	$ 10,528	$ 5,658	$ 5,867	$ 5,594	$ 2,275
Amortization of Capital Leases	7,940	668	6,200	478	249
Interest on Capital Leases	2,275	93	2,738	60	34
Total Lease Rental Costs	$ 20,743	$ 6,419	$ 14,805	$ 6,132	$ 2,558

Year Ended December 31, 2004	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Lease Payments on Operating Leases	$ 75,545	$ 6,832	$ 5,313	$ 111,344	$ 1,416
Amortization of Capital Leases	92	7,906	3,933	6,825	1,605
Interest on Capital Leases	7	1,260	705	1,403	258
Total Lease Rental Costs	$ 75,644	$ 15,998	$ 9,951	$ 119,572	$ 3,279

Year Ended December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Lease Payments on Operating Leases	$ 14,390	$ 3,697	$ 4,877	$ 3,949	$ 1,458
Amortization of Capital Leases	8,232	520	3,543	437	216
Interest on Capital Leases	2,259	53	2,054	66	27
Total Lease Rental Costs	$ 24,881	$ 4,270	$ 10,474	$ 4,452	$ 1,701

Year Ended December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Lease Payments on Operating Leases	$ 76,322	$ 6,148	$ 5,277	$ 111,923	$ 1,258
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951
Interest on Capital Leases	-	1,123	899	1,276	148
Total Lease Rental Costs	$ 76,591	$ 16,488	$ 11,074	$ 120,569	$ 3,357

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Lease Payments on Operating Leases	$ 40,034	$ 4,883	$ 4,708	$ 6,360	$ 2,132
Amortization of Capital Leases	9,437	174	1,434	161	83
Interest on Capital Leases	2,472	17	899	16	9
Total Lease Rental Costs	$ 51,943	$ 5,074	$ 7,041	$ 6,537	$ 2,224

Property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries' balance sheets are as follows:

As of December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,316	$ 1,275	$ 7,104	$ 18,964	$ 436
Distribution	-	-	-	14,589	-
Other	349	36,792	16,059	38,568	9,128
Total Property, Plant and Equipment	12,665	38,067	23,163	72,121	9,564
Accumulated Amortization	438	23,185	13,609	28,145	6,396
Net Property, Plant and Equipment Under Capital Leases	$ 12,227	$ 14,882	$ 9,554	$ 43,976	$ 3,168
Obligations Under Capital Leases:					
Noncurrent Liability	$ 11,930	$ 9,292	$ 6,545	$ 38,645	$ 2,030
Liability Due Within One Year	297	5,600	3,031	5,331	1,138
Total Obligations Under Capital Leases	$ 12,227	$ 14,892	$ 9,576	$ 43,976	$ 3,168

As of December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases:					
Production	$ 40,554	$ -	$ 14,270	$ -	$ -
Distribution	-	-	-	-	-
Other	37,867	3,378	65,014	2,072	1,045
Total Property, Plant and Equipment	78,421	3,378	79,284	2,072	1,045
Accumulated Amortization	39,912	844	36,803	694	321
Net Property, Plant and Equipment Under Capital Leases	$ 38,509	$ 2,534	$ 42,481	$ 1,378	$ 724
Obligations Under Capital Leases:					
Noncurrent Liability	$ 30,750	$ 1,778	$ 37,055	$ 888	$ 506
Liability Due Within One Year	9,174	756	5,490	490	218
Total Obligations Under Capital Leases	$ 39,924	$ 2,534	$ 42,545	$ 1,378	$ 724

As of December 31, 2004	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,339	$ 1,759	$ 7,104	$ 22,917	$ 797
Distribution	-	-	-	14,589	-
Other	353	45,892	21,270	43,478	10,405
Total Property, Plant and Equipment	12,692	47,651	28,374	80,984	11,202
Accumulated Amortization	218	27,709	15,884	30,252	6,839
Net Property, Plant and Equipment Under Capital Leases	$ 12,474	$ 19,942	$ 12,490	$ 50,732	$ 4,363
Obligations Under Capital Leases:					
Noncurrent Liability	$ 12,264	$ 13,136	$ 8,660	$ 44,608	$ 2,802
Liability Due Within One Year	210	6,742	3,854	6,124	1,561
Total Obligations Under Capital Leases	$ 12,474	$ 19,878	$ 12,514	$ 50,732	$ 4,363

As of December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases:					
Production	$ 34,796	$ -	$ 14,269	$ -	$ -
Distribution	-	-	-	-	-
Other	46,131	1,813	53,620	1,364	780
Total Property, Plant and Equipment	80,927	1,813	67,889	1,364	780
Accumulated Amortization	41,187	529	33,343	484	246
Net Property, Plant and Equipment Under Capital Leases	$ 39,740	$ 1,284	$ 34,546	$ 880	$ 534
Obligations Under Capital Leases:					
Noncurrent Liability	$ 31,652	$ 747	$ 30,854	$ 468	$ 314
Liability Due Within One Year	9,081	537	3,692	412	220
Total Obligations Under Capital Leases	$ 40,733	$ 1,284	$ 34,546	$ 880	$ 534

Future minimum lease payments consisted of the following at December 31, 2005:

Capital Leases	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
2006	$ 996	$ 6,741	$ 3,489	$ 9,182	$ 1,309
2007	987	4,057	2,519	15,403	1,065
2008	977	3,500	2,344	5,686	612
2009	968	1,381	1,334	4,290	251
2010	963	1,118	977	2,201	166
Later Years	17,036	293	4	20,768	89
Total Future Minimum Lease Payments	21,927	17,090	10,667	57,530	3,492
Less Estimated Interest Element	9,700	2,198	1,091	13,554	324
Estimated Present Value of Future Minimum Lease Payments	$ 12,227	$ 14,892	$ 9,576	$ 43,976	$ 3,168

Capital Leases	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
2006	$ 10,080	$ 870	$ 8,498	$ 547	$ 249
2007	8,316	666	8,341	362	165
2008	6,215	497	8,228	291	144
2009	4,329	397	7,791	219	133
2010	3,700	272	3,871	106	87
Later Years	22,426	150	22,847	4	39
Total Future Minimum Lease Payments	55,066	2,852	59,576	1,529	817
Less Estimated Interest Element	15,142	318	17,031	151	93
Estimated Present Value of Future Minimum Lease Payments	$ 39,924	$ 2,534	$ 42,545	$ 1,378	$ 724

Noncancelable Operating Leases	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
2006	$ 77,474	$ 9,772	$ 4,110	$ 100,745	$ 1,820
2007	77,180	7,797	3,553	98,324	1,564
2008	77,178	6,286	2,934	95,815	1,256
2009	77,175	5,555	2,558	94,833	1,097
2010	77,023	4,572	2,002	91,467	1,020
Later Years	890,920	11,502	4,001	949,711	1,942
Total Future Minimum Lease Payments	$ 1,276,950	$ 45,484	$ 19,158	$ 1,430,895	$ 8,699

Noncancelable Operating Leases	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
2006	$ 17,869	$ 6,223	$ 6,236	$ 5,848	$ 2,418
2007	16,920	5,639	5,748	4,972	2,061
2008	15,973	3,600	5,030	3,534	1,831
2009	15,003	3,049	4,286	3,037	1,933
2010	13,578	3,417	2,934	3,304	1,599
Later Years	65,561	6,348	6,382	3,838	2,367
Total Future Minimum Lease Payments	$ 144,904	$ 28,276	$ 30,616	$ 24,533	$ 12,209

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct, own and lease the Gavin Scrubber for the Gavin Plant to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($470 million). Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for as an operating lease, with a non-affiliated third party. For the first half of 2003, OPCo recorded operating lease payments related to the Gavin Scrubber as operating lease expense. After July 1, 2003, OPCo has recorded the depreciation, interest and other operating expenses of JMG and has eliminated JMG's rental revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of the requirement to consolidate JMG and there was no change in net income due to the consolidation of JMG. The debt obligations of JMG are now included in long-term debt as Notes Payable and Installment Purchase Contracts and are excluded from the above table of future minimum lease payments.

At any time during the obligation, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year term is noncancelable. At the end of the initial term, OPCo can renew the obligation, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In the case of a sale at less than the adjusted acquisition cost, OPCo is required to pay the difference to JMG.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company as of December 31, 2005 are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

16. FINANCING ACTIVITIES

Preferred Stock

Registrant Subsidiary	Par Value	Authorized Shares	Shares Outstanding at December 31, 2005	Call Price at December 31, 2005 (a)	Series	Redemption	December 31, 2005	December 31, 2004
							(in thousands)	
APCo	$ 0(b)	8,000,000	177,836	$ 110.00	4.50%	Any time	$ 17,784	$ 17,784
CSPCo	25	7,000,000	-	-	-	-	-	-
CSPCo	100	2,500,000	-	-	-	-	-	-
I&M	25	11,200,000	-	-	-	-	-	-
I&M	100	(c)	55,369	106.125	4.125%	Any time	5,537	5,537
I&M	100	(c)	14,412	102.000	4.560%	Any time	1,441	1,441
I&M	100	(c)	11,055	102.728	4.120%	Any time	1,106	1,106
I&M	100	(c)	-	-	5.900%	1/1/2009	-	13,200
I&M	100	(c)	-	-	6.250%	4/1/2009	-	19,250
I&M	100	(c)	-	-	6.300%	7/1/2009	-	13,245
I&M	100	(c)	-	-	6.875%	4/1/2008	-	15,750
OPCo	25	4,000,000	-	-	-	-	-	-
OPCo	100	(d)	14,595	103.00	4.08%	Any time	1,460	1,460
OPCo	100	(d)	22,824	103.20	4.20%	Any time	2,282	2,282
OPCo	100	(d)	31,512	104.00	4.40%	Any time	3,151	3,151
OPCo	100	(d)	97,462	110.00	4.50%	Any time	9,746	9,748
OPCo	100	(d)	-	-	5.90%	1/1/2009	-	5,000
PSO	100	(e)	44,548	105.75	4.00%	Any time	4,455	4,455
PSO	100	(e)	8,069	103.19	4.24%	Any time	807	807
SWEPCo	100	(f)	7,386	103.90	4.28%	Any time	740	740
SWEPCo	100	(f)	1,907	102.75	4.65%	Any time	190	190
SWEPCo	100	(f)	37,703	109.00	5.00%	Any time	3,770	3,770
TCC	100	(g)	41,922	105.75	4.00%	Any time	4,192	4,192
TCC	100	(g)	17,476	103.75	4.20%	Any time	1,748	1,748
TNC	100	810,000	23,566	107.00	4.40%	Any time	2,357	2,357

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Stated value is $100 per share.
(c) I&M has 2,250,000 authorized $100 par value per share shares in total.
(d) OPCo has 3,762,403 authorized $100 par value per share shares in total.
(e) PSO has 700,000 authorized shares in total.
(f) SWEPCo has 1,860,000 authorized shares in total.
(g) TCC has 3,035,000 authorized shares in total.

Registrant	Series	Number of Shares Redeemed for the Year Ended December 31, 2005	2004	2003
APCo	4.50%	-	3	60
APCo	5.90%	-	22,100	25,000
APCo	5.92%	-	31,500	30,000
I&M	4.120%	-	175	-
I&M	5.90%	132,000	20,000	-
I&M	6.25%	192,500	-	-
I&M	6.30%	132,450	-	-
I&M	6.875%	157,500	-	15,000
OPCo	4.50%	20	41	23
OPCo	5.90%	50,000	22,500	-
PSO	4.00%	-	50	2
SWEPCo	5.00%	-	-	12
TCC	4.00%	-	5	11
TNC	4.40%	-	4	102

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2005 and 2004:

Registrant	Maturity	Weighted Average Interest Rate at December 31, 2005	Interest Rates at December 31, 2005	Interest Rates at December 31, 2004	December 31, 2005	December 31, 2004
					(in thousands)	
INSTALLMENT PURCHASE CONTRACTS (a)						
AEGCo	2025(b)	4.05%	4.05%	4.05%	$ 44,828	$ 44,820
APCo	2007-2024 (c)	4.57%	2.70%-6.05%	1.85%-6.05%	236,771	236,759
CSPCo	2038	3.27%	3.20%-3.35%	1.75%-2.00%	92,082	92,077
I&M	2009-2025 (d)	3.89%	2.625%-6.55%	1.75%-6.55%	311,267	311,230
OPCo	2014-2029	3.63%	3.10%-5.5625%	2.10%-6.375%	492,130	490,028
PSO	2014-2020	3.93%	3.15%-6.00%	1.75%-6.00%	46,360	46,360
SWEPCo	2011-2019	4.58%	3.10%-6.10%	1.70%-6.10%	177,678	177,879
TCC	2015-2030 (e)	3.95%	3.15%-6.125%	2.15%-6.125%	489,603	327,894
TNC	2020	6.00%	6.00%	6.00%	44,310	44,310
SENIOR UNSECURED NOTES						
APCo	2005-2035	5.05%	3.60%-6.60%	2.88%-6.60%	1,713,476	1,320,663
CSPCo	2005-2035	5.81%	4.40%-6.60%	4.40%-6.85%	1,004,838	795,549
I&M	2006-2032	5.88%	5.05%-6.45%	5.05%-6.45%	898,398	772,712
KPCo	2007-2032	5.34%	4.3148%-6.91%	4.31%-6.91%	427,790	428,310
OPCo	2008-2033	5.76%	4.85%-6.60%	4.85%-6.60%	1,181,869	983,008
PSO	2009-2032	5.29%	4.70%-6.00%	4.70%-6.00%	474,711	399,762
SWEPCo	2005-2015	5.09%	4.90%-5.375%	4.50%-5.375%	249,801	299,686
TCC	2005-2033	6.08%	5.50%-6.65%	3.00%-6.65%	548,042	797,863
TNC	2013	5.50%	5.50%	5.50%	224,385	224,295
FIRST MORTGAGE BONDS (f)						
APCo	2005-2025	6.80%	6.80%	6.80%-8.00%	99,987	224,662
PSO	2005	-	-	6.50%	-	49,970
SWEPCo	2006-2007	6.95%	6.20%-7.00%	6.20%-7.00%	95,951	96,024
TCC	2005-2008	7.125%	7.125%	6.625%-7.125%	18,581	84,344
TNC	2005-2007	7.75%	7.75%	6.375%-7.75%	8,150	45,752
NOTES PAYABLE - AFFILIATED						
APCo	2010	4.708%	4.708%	-	100,000	-
CSPCo	2010	4.64%	4.64%	4.64%	100,000	100,000
KPCo	2006-2015	6.08%	5.25%-6.501%	5.25%-6.501%	60,000	80,000
OPCo	2006-2015	4.29%	3.32%-5.25%	3.32%-5.25%	400,000	400,000
PSO	2006	3.35%	3.35%	3.35%	50,000	50,000
SWEPCo	2010	4.45%	4.45%	4.45%	50,000	50,000
TCC	2007	4.58%	4.58%	-	150,000	-
NOTES PAYABLE – NONAFFILIATED						
OPCo	2008-2009	7.09%	6.27%-7.49%	6.27%-7.49%	125,671	138,024
SWEPCo	2006-2012	5.56%	4.47%-7.03%	2.325%-7.03%	59,577	68,761
SECURITIZATION BONDS						
TCC	2007-2017	5.78%	5.01%-6.25%	3.54%-6.25%	647,270	697,193
NOTES PAYABLE TO TRUST						
SWEPCo	2043	5.25%	5.25%	5.25%	113,029	113,019
OTHER LONG-TERM DEBT						
APCo	2026	13.718%	13.718%	13.718%	2,504	2,514
I&M (g)	-	-	-	-	235,805	228,901

(a) Under the terms of the installment purchase contracts, each Registrant Subsidiary is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Interest payments range from monthly to semi-annually.

(b) The bonds due in 2025 are subject to mandatory tender for purchase in July 2006. Consequently, the bonds have been classified for repayment purposes in 2006.

(c) The fixed rate bonds due 2007 and 2019 are subject to mandatory tender for purchase on November 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006.

(d) The fixed rate bonds due 2019 and 2025 are subject to mandatory tender for purchase on October 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006. The term rate bonds due 2025 are subject to mandatory tender for purchase on the term maturity date (June 1, 2007). Accordingly, the term rate bonds have been classified for repayment purposes in 2007 (the term end date).

(e) Installment purchase contract maturing in 2029 provides for bonds to be tendered in 2006. Therefore, this installment purchase contract has been classified for payment in 2006.

(f) First mortgage bonds are secured by the first mortgage liens on Electric Property, Plant and Equipment. Certain supplemental indentures to the first mortgage liens contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually. In 2004, TCC's first mortgage bonds were defeased and in 2005, TNC's first mortgage bonds were defeased.

(g) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets of $264 million and $262 million related to this obligation are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds in its Consolidated Balance Sheets at December 31, 2005 and 2004, respectively.

At December 31, 2005, future annual long-term debt payments are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2006	$ 45,000	$ 146,999	$ -	$ 364,469	$ 39,771
2007	-	324,445	-	50,000	322,393
2008	-	199,734	112,000	50,000	30,000
2009	-	150,017	-	45,000	-
2010	-	250,019	250,000	-	-
Later Years	-	1,091,930	842,245	937,805	95,000
Total Principal Amount	45,000	2,163,144	1,204,245	1,447,274	487,164
Unamortized Discount	(172)	(11,766)	(7,325)	(2,334)	(174)
Total	$ 44,828	$ 2,151,378	$ 1,196,920	$ 1,444,940	$ 486,990

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2006	$ 212,354	$ 50,000	$ 17,149	$ 152,900	$ -
2007	17,854	-	102,312	202,729	8,150
2008	55,188	-	5,906	68,688	-
2009	77,500	50,000	4,406	53,627	-
2010	200,000	150,000	54,406	56,575	-
Later Years	1,642,130	321,360	561,206	1,321,673	269,310
Total Principal Amount	2,205,026	571,360	745,385	1,856,192	277,460
Unamortized Premium/(Discount)	(5,356)	(289)	650	(2,696)	(615)
Total	$ 2,199,670	$ 571,071	$ 746,035	$ 1,853,496	$ 276,845

In February 2006, APCo issued $50,275,000 variable rate installment purchase contracts maturing in February 2036. In February 2006, an affiliate issued TCC a 5.14%, $125 million note due August 2007.

Dividend Restrictions

Under the Federal Power Act, the Registrants Subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

Trust Preferred Securities

SWEPCO has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. In addition, PSO and TCC had trusts that were deconsolidated in 2003 due to the implementation of FIN 46. The Junior Subordinated Debentures held in the trust for PSO and TCC were retired in 2004. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2005 and 2004, is reported as Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2005 and 2004, are reported as Notes Payable to Trust within Long-term Debt – Nonaffiliated.

The business trust is treated as a nonconsolidated subsidiary of its parent company. The only asset of the business trust is the subordinated debentures issued by its parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The Utility Money Pool participants' money pool activity and corresponding authorized limits for the years ended December 31, 2005 and 2004 are described in the following tables:

Year Ended December 31, 2005:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31, 2005	Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 45,694	$ 9,305	$ 15,551	$ 4,272	$ (35,131)	$ 125,000
APCo	242,718	321,977	134,079	44,622	(194,133)	600,000
CSPCo	180,397	181,238	143,885	94,083	(17,609)	350,000
I&M	203,248	11,768	87,208	5,797	(93,702)	500,000
KPCo	9,964	35,779	2,969	12,653	(6,040)	200,000
OPCo	162,907	182,495	64,142	75,186	(70,071)	600,000
PSO	101,962	66,159	30,205	32,632	(75,883)	300,000
SWEPCo	55,756	188,215	17,657	34,490	(28,210)	350,000
TCC	320,508	120,937	109,463	39,060	(82,080)	600,000
TNC	13,606	119,569	10,930	58,067	34,286	250,000

Year Ended December 31, 2004:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31, 2004	Authorized Short-Term Borrowing Limit
	(in thousands)					
AEGCo	$ 56,525	$ 932	$ 23,532	$ 731	$ (26,915)	$ 125,000
APCo	211,060	32,575	76,100	13,501	(211,060)	600,000
CSPCo	29,687	184,962	12,808	75,580	141,550	350,000
I&M	216,528	70,363	89,578	29,290	5,093	500,000
KPCo	44,749	41,501	13,580	15,282	16,127	200,000
OPCo	81,862	297,136	29,578	152,442	125,971	600,000
PSO	145,619	35,158	47,099	16,204	(55,002)	300,000
SWEPCo	71,252	107,966	38,073	64,386	39,106	350,000
TCC	109,696	427,414	62,494	120,312	(207)	600,000
TNC	16,136	110,430	6,704	41,500	51,504	250,000

The maximum and minimum interest rates for funds either borrowed or loaned to the Utility Money Pool for the years ended December 31, 2005 and 2004 were 4.49% and 1.63% and 2.24% and 0.89%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2005 and 2004 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Year Ended December 31, 2005	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Year Ended December 31, 2004	Average Interest Rate for Funds Loaned to the Utility Money Pool for Year Ended December 31, 2005	Average Interest Rate for Funds Loaned to the Utility Money Pool for Year Ended December 31, 2004
	(in percentage)			
AEGCo	3.27	1.47	3.17	1.91
APCo	3.40	1.68	3.15	1.48
CSPCo	3.95	1.50	3.03	1.69
I&M	3.43	1.45	2.12	1.93
KPCo	3.70	1.59	2.70	1.61
OPCo	3.86	1.29	2.57	1.46
PSO	3.37	1.38	3.56	1.80
SWEPCo	4.10	1.37	2.62	1.67
TCC	3.18	1.40	2.43	1.47
TNC	4.41	1.09	3.29	1.56

As of December 31, 2005, AEP had credit facilities totaling $2.5 billion to support its commercial paper program. As of December 31, 2005, AEP's commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%. In September 2005, Moody's Investors Service upgraded AEP's commercial paper rating to Prime-2 from Prime-3.

At December 31, 2005 and 2004, OPCo had $10 million and $23 million, respectively, in outstanding commercial paper related to JMG, reflected as Short-term Debt – Nonaffiliated on OPCo's Consolidated Balance Sheets. The interest rate of the JMG commercial paper at December 31, 2005 and 2004 was 4.47% and 2.50%, respectively. This commercial paper is specifically associated with the Gavin Scrubber as identified in the "Gavin Scrubber Financing Arrangement" section of Note 15. This commercial paper does not reduce AEP's available liquidity.

Interest expense related to the Utility Money Pool is included in Interest Expense in each of the Registrant Subsidiaries' Financial Statements. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
AEGCo	$ 418	$ 338	$ 289
APCo	2,830	1,136	147
CSPCo	280	32	732
I&M	2,854	1,127	313
KPCo	18	65	897
OPCo	1,056	51	2,332
PSO	637	486	1,218
SWEPCo	293	219	787
TCC	3,272	177	617
TNC	8	8	449

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' Financial Statements. Interest income earned from amounts advanced to the Utility Money Pool by Registrant Subsidiary were:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
AEGCo	$ 24	$ 1	$ 8
APCo	543	24	1,589
CSPCo	2,757	1,076	777
I&M	6	84	1,814
KPCo	287	177	-
OPCo	1,129	1,965	700
PSO	431	76	156
SWEPCo	649	649	662
TCC	66	1,445	589
TNC	1,897	587	164

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit's sale of receivables agreement expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2005	Year Ended December 31, 2004
	($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,925	$ 5,163
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 106	$ 80
Deferred Revenue from Servicing Accounts Receivable	$ 1	$ 1
Loss on Sale of Accounts Receivables	$ 18	$ 7
Average Variable Discount Rate	3.23 %	1.50 %
Retained Interest if 10% Adverse Change in Uncollectible Accounts	$ 103	$ 78
Retained Interest if 20% Adverse Change in Uncollectible Accounts	$ 101	$ 76

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2005	Face Value December 31, 2004
	($ in millions)	
Customer Accounts Receivable Retained	$ 826	$ 830
Accrued Unbilled Revenues Retained	374	665
Miscellaneous Accounts Receivable Retained	51	84
Allowance for Uncollectible Accounts Retained	(31)	(77)
Total Net Balance Sheet Accounts Receivable	1,220	1,502
Customer Accounts Receivable Securitized	516	435
Total Accounts Receivable Managed	$ 1,736	$ 1,937
Net Uncollectible Accounts Written Off	$ 74	$ 86

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $30 million and $25 million at December 31, 2005 and 2004, respectively.

Under the factoring arrangement, participating Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the participant's Statements of Income.

The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

	As of December 31, 2005	2004
	(in millions)	
APCo	$ 77.1	$ 58.7
CSPCo	124.4	110.1
I&M	102.7	91.4
KPCo	38.7	34.4
OPCo	122.1	106.0
PSO	146.5	96.7
SWEPCo	100.4	72.0

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31, 2005	2004	2003
		(in millions)	
APCo	$ 5.1	$ 3.9	$ 3.4
CSPCo	7.4	10.2	9.8
I&M	7.4	6.5	6.1
KPCo	2.9	2.6	2.4
OPCo	6.1	7.7	8.7
PSO	11.1	8.9	5.8
SWEPCo	8.3	5.8	4.9

17. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit" sections of Note 16.

AEP System Power Pool

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

Power, gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts includes exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the AEP West companies to maintain adequate annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy each AEP West company contributes that is sold to third parties. Upon sale of its generation assets, TCC will no longer supply generating capacity under the CSW Operating Agreement.

On February 10, 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement since, pursuant to Texas electric restructuring law, those companies exited, or are in the process of exciting, the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the System Integration Agreement. The matter is pending before the FERC.

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

On November 1, 2005, AEP filed with the FERC a proposed amendment to the System Integration Agreement to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method would cause such profits to be allocated generally on the basis of the zone in which the underlying transactions occurred or originated. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006. The matter is pending before the FERC.

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such Registrant Subsidiary at rates approved (other than in Ohio, Virginia and the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation (see Note 6).

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

AEP East Companies and AEP West Companies Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2005, 2004 and 2003:

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2005						
Sales to East System Pool	$ 162,014	$ 70,165	$ 314,677	$ 49,791	$ 542,364	$ -
Direct Sales to East Affiliates	70,130	-	-	-	64,449	270,545
Direct Sales to West Affiliates	25,776	14,162	14,998	6,122	19,562	-
Natural Gas Contracts with AEPES	60,793	34,324	33,461	14,586	46,751	-
Other	3,620	5,759	2,896	304	8,726	-
Total Revenues	$ 322,333	$ 124,410	$ 366,032	$ 70,803	$ 681,852	$ 270,545

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
	(in thousands)					
2004						
Sales to East System Pool	$ 138,566	$ 69,309	$ 250,356	$ 36,853	$ 487,794	$ -
Direct Sales to East Affiliates	62,018	-	-	-	55,017	241,578
Direct Sales to West Affiliates	22,238	13,322	14,682	5,206	17,899	-
Natural Gas Contracts with AEPES	25,733	15,732	17,886	6,306	22,971	-
Other	3,573	6,384	3,386	352	10,676	-
Total Revenues	$ 252,128	$ 104,747	$ 286,310	$ 48,717	$ 594,357	$ 241,578

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
	(in thousands)					
2003						
Sales to East System Pool	$ 136,581	$ 59,184	$ 238,538	$ 33,607	$ 490,896	$ -
Direct Sales to East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales to West Affiliates	27,978	16,437	17,691	6,432	21,780	-
Natural Gas Contracts with AEPES	39,010	21,971	24,082	8,877	29,065	-
Other	3,138	8,715	2,783	550	8,298	-
Total Revenues	$ 267,345	$ 106,307	$ 283,094	$ 49,466	$ 600,803	$ 232,955

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2005				
Direct Sales to West Affiliates	$ 33,992	$ 61,555	$ -	$ 98
Other	5,686	3,853	14,973	47,066
Total Revenues	$ 39,678	$ 65,408	$ 14,973	$ 47,164

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2004				
Sales to West System Pool	$ 103	$ 521	$ -	$ 159
Direct Sales to East Affiliates	2,652	1,878	188	78
Direct Sales to West Affiliates	3,203	63,141	3,027	71
Other	4,732	5,650	43,824	51,372
Total Revenues	$ 10,690	$ 71,190	$ 47,039	$ 51,680

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2003				
Sales to West System Pool	$ 793	$ 600	$ 15,157	$ 651
Direct Sales to East Affiliates	1,159	706	677	6
Direct Sales to West Affiliates	17,855	64,802	23,248	1,929
Other	3,323	2,746	114,688	52,800
Total Revenues	$ 23,130	$ 68,854	$ 153,770	$ 55,386

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2005, 2004, and 2003:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2005					
Purchases from East System Pool	$ 453,600	$ 362,959	$ 116,735	$ 95,187	$ 104,777
Direct Purchases from East Affiliates	-	-	189,382	81,163	12,113
Total Purchases	$ 453,600	$ 362,959	$ 306,117	$ 176,350	$ 116,890

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2004					
Purchases from East System Pool	$ 370,038	$ 346,463	$ 102,760	$ 68,072	$ 84,042
Direct Purchases from East Affiliates	-	-	169,103	72,475	4,334
Direct Purchases from West Affiliates	915	539	589	211	979
Total Purchases	$ 370,953	$ 347,002	$ 272,452	$ 140,758	$ 89,355

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2003					
Purchases from East System Pool	$ 348,899	$ 335,916	$ 109,826	$ 71,259	$ 88,962
Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
Direct Purchases from West Affiliates	765	471	505	182	625
Total Purchases	$ 351,210	$ 337,323	$ 274,400	$ 141,690	$ 90,821

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2005				
Purchases from East System Pool	$ 43,516	$ 36,573	$ -	$ -
Direct Purchases from East Affiliates	281	278	-	-
Direct Purchases from West Affiliates	61,564	34,060	-	23
Total Purchases	$ 105,361	$ 70,911	$ -	$ 23

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2004				
Purchases from East System Pool	$ 66	$ 177	$ -	$ -
Purchases from West System Pool	49	191	-	568
Direct Purchases from East Affiliates	45,689	24,988	1,984	1,278
Direct Purchases from West Affiliates	58,197	3,698	4,156	3,365
Total Purchases	$ 104,001	$ 29,054	$ 6,140	$ 5,211

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2003				
Purchases from East System Pool	$ 639	$ -	$ -	$ -
Purchases from West System Pool	704	741	289	15,467
Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
Other	-	710	-	-
Total Purchases	$ 109,639	$ 47,914	$ 19,097	$ 39,409

The above summarized related party revenues and expenses are reported as consolidated and are presented as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the income statements of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net charges (credits) allocated among the parties to the Transmission Agreement during the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
		(in thousands)	
APCo	$ 8,900	$ (500)	$ -
CSPCo	34,600	37,700	38,200
I&M	(47,000)	(40,800)	(39,800)
KPCo	(3,500)	(6,100)	(5,600)
OPCo	7,000	9,700	7,200

The net charges (credits) shown above are recorded in Other Operation in the Registrant Subsidiaries' income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated January 1, 1997 (TCA). The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net charges (credits) allocated among parties to the TCA during the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
		(in thousands)	
PSO	$ 3,500	$ 8,100	$ 4,200
SWEPCo	5,200	13,800	5,000
TCC	(3,800)	(12,200)	(3,600)
TNC	(4,900)	(9,700)	(5,600)

The net charges (credits) shown above are recorded in the Other Operation portion of the Registrant Subsidiaries' income statements.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's East companies and West companies zones. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

CSPCo coal purchases from AEP Coal, Inc.

During 2004, CSPCo purchased approximately 330,000 tons of coal from AEP Coal. The coal was delivered (at CSPCo's expense) to the Conesville Plant for a price of $26.15 per ton. In 2003, AEP Coal and CSPCo were parties to a coal purchase agreement dated October 15, 2002. The agreement provided for CSPCo's purchase of up to 960,000 tons of coal to be delivered (at CSPCo's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. During 2004 and 2003, CSPCo's purchases from AEP Coal totaled $9.5 million and $23.9 million, respectively. These purchases were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

AEP Coal and CSPCo were parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, in 2004 and 2003 AEP Coal transferred coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivered the coal via trucks to either CSPCo's Conesville Preparation Plant or CSPCo's power plant for a rate of $1.25 per ton. During 2004 and 2003, CSPCo paid AEP Coal $1.0 million and $3.4 million, respectively. These transloading costs were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

As a result of management's decision to exit our non-core businesses, AEP Coal, Inc. (AEP Coal) was sold in March 2004.

Coal Transactions with AEP Coal Marketing

AEP Coal Marketing, a wholly-owned subsidiary of AEP, enters into sale and purchase transactions with certain operating companies. The transactions are executed on a spot basis and are performed at cost for the operating companies' fuel requirements. During 2005 and 2004, the only transactions were immaterial purchases by I&M and OPCo from AEP Coal Marketing. During 2003, I&M's net coal inventory sales to AEP Coal Marketing totaled $11.4 million.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents Registrant Subsidiaries' risk management liabilities at December 31,:

Company	2005	2004
	(in thousands)	
APCo	$ (12,318)	$ (23,736)
CSPCo	(7,142)	(13,654)
I&M	(7,294)	(15,266)
KPCo	(2,932)	(5,570)
OPCo	(9,810)	(19,065)
Total	$ (39,496)	$ (77,291)

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who purchase 100% of the available generating capacity from the plant through May 2006. The related purchases of gas managed by AEPES were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
APCo	$ 3,905	$ 1,230	$ 1,546
CSPCo	2,113	732	936
I&M	2,255	805	1,000
KPCo	924	286	363
OPCo	2,916	1,281	1,234
Total	$ 12,113	$ 4,334	$ 5,079

These purchases are reflected in Purchased Electricity for Resale in the Registrant Subsidiaries' income statements.

Unit Power Agreements

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

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

Jointly-Owned Electric Utility Plants

APCo and OPCo jointly own two power plants. The costs of operating these facilities are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective Consolidated Statements of Income. Each company's investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

AEG and I&M jointly own one generating unit and jointly lease the other generating unit of the Rockport Plant. The costs of operating this facility are equally apportioned between AEG and I&M since each company has a 50% interest. Each company's share of costs is included in the appropriate expense accounts in its respective income statements. Each company's investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

Cook Coal Terminal

In 2005, 2004 and 2003, Cook Coal Terminal, a division of OPCo, performed coal transloading services at cost for APCo and I&M. OPCo's revenues for these services are included in Other-Affiliated and its expenses are included in Other Operation on its Consolidated Statements of Income. The revenues were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
APCo	$ 1,770	$ 730	$ -
I&M	13,653	14,275	13,114

APCo and I&M recorded the cost of the transloading services in Fuel on their respective Consolidated Balance Sheets.

In addition, Cook Coal Terminal provided coal transloading services for Ohio Valley Electric Corporation (OVEC) in 2005. The revenue recorded by OPCo and reported as Other – Nonaffiliated on its Consolidated Statements of Income was $513 thousand in 2005. OVEC is 43.47% owned by AEP and CSPCo.

I&M Barging and Other Services

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as Other – Affiliated on its Consolidated Statements of Income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2005	2004	2003
Company		(in millions)	
I&M – revenues	$ 43.1	$ 38.2	$ 31.9
AEGCo – expense	11.4	9.5	8.1
APCo – expense	18.5	13.0	12.3
KPCo – expense	0.1	0.1	0.1
OPCo – expense	2.5	4.9	4.3
MEMCO – expense (Nonutility subsidiary of AEP)	10.6	10.7	7.1

Services Provided by MEMCO

AEP MEMCO LLC (MEMCO) provides services for barge towing and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation. For the years ended December 31, 2005, 2004 and 2003, I&M recorded $14.1 million, $12.6 million and $8.8 million, respectively.

Gas Purchases from HPL

Prior to its sale in January 2005, HPL acquired physical gas in the spot market. The gas was then purchased by TCC and TNC at cost for their fuel requirements. These purchases are included in Fuel from Affiliates for Electricity Generation on TCC's and TNC's respective income statements. The purchases from HPL were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
TCC	$ -	$ 129,682	$ 195,527
TNC	42	45,767	44,197

OPCo Indemnification Agreement with AEP Resources

OPCo has an indemnification agreement with AEP Resources (AEPR), a nonutility subsidiary of AEP, whereby AEPR holds OPCo harmless from market exposure related to OPCo's Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2005 and 2004, AEPR paid OPCo $29.6 million and $21.5 million, respectively, which is reported in OPCo's Other Operation in its Consolidated Statements of Income. See "Power Generation Facility – Affecting OPCo" section of Note 7 for further discussion.

Purchased Power from Ohio Valley Electric Corporation

The amounts of power purchased by the Registrant Subsidiaries from Ohio Valley Electric Corporation, which is 43.47% owned by AEP and CSPCo, for the years ended December 31, 2005, 2004 and 2003 were:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
APCo	$ 77,337	$ 62,101	$ 55,219
CSPCo	20,602	16,724	15,259
I&M	30,961	27,474	25,659
OPCo	66,680	55,052	50,995

The amounts shown above are included in Purchased Electricity for Resale in the Registrant Subsidiaries' respective Consolidated Statements of Income.

Purchased Power from Sweeny

On behalf of the AEP West companies CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, which is 50% owned by AEP. The PPA is for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. The purchase of Sweeny power and its sale to nonaffiliates are shared among the AEP West companies under the CSW Operating Agreement. The purchases from Sweeny were:

Company	Year Ended December 31, 2005 (in thousands)
PSO	$ 57,742
SWEPCo	50,618
TCC	4,560
TNC	27,804

The amounts shown above are recorded in Purchased Electricity for Resale in the Registrant Subsidiaries' respective income statements.

OPCo Coal Transfers

In 2005, OPCo sold 142,226 tons of coal from its Mitchell plant inventory to APCo for $5,960,328. The coal was sold at cost, based on a weighted average cost method of carrying inventory. APCo paid for the cost of transporting the coal from OPCo's facility to its delivery point at APCo's Amos plant. The amount above was transferred from Fuel on OPCo's Consolidated Balance Sheet to APCo's Consolidated Balance Sheet at the time of the sale.

In 2005, OPCo also sold 30,844 tons of coal from its Gavin plant inventory to OVEC for $745,191. The coal was sold at cost, based on a weighted average cost method of carrying inventory. OVEC paid for the cost of transporting the coal from OPCO's facility to its delivery point at OVEC's Kyger Creek plant. The coal inventory had been recorded in Fuel on OPCo's Consolidated Balance Sheet at the time of the sale.

Sales of Property

The Registrant Subsidiaries had sales of electric property for the years ended December 31, 2005, 2004 and 2003 as shown in the following table.

	2005 (in thousands)
APCo to I&M	$ 554
APCo to OPCo	637
I&M to APCo	1,135
I&M to OPCo	3,423
KPCo to OPCo	101
OPCo to APCo	1,057
OPCo to I&M	2,142

	2004 (in thousands)
APCo to OPCo	$ 2,992
I&M to APCo	1,630

	2003 (in thousands)
AEGCo to OPCo	$ 105
APCo to OPCo	1,079
I&M to OPCo	1,492
OPCo to APCo	2,768
OPCo to I&M	1,096

The electric property amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. During the reporting periods, AEPSC and its billings were subject to regulation by the SEC under the PUHCA.

8. JOINTLY-OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly-owned with affiliated and nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2005		2004	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
CSPCo		(in thousands)			
W.C. Beckjord Generating Station (Unit No. 6)	12.5%	$ 15,681	$ 52	$ 15,531	$ 139
Conesville Generating Station (Unit No. 4)	43.5	85,162	7,583	85,036	654
J.M. Stuart Generating Station	26.0	266,136	35,461	209,842	60,535
Wm. H. Zimmer Generating Station	25.4	749,112	2,295	741,043	7,976
Transmission	(a)	62,553	1,344	62,287	3,744
Total		$ 1,178,644	$ 46,735	$ 1,113,739	$ 73,048
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6%	$ 86,051	$ 700	$ 85,834	$ 345
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2%	$ 237,941	$ 3,829	$ 237,741	$ 2,559
Flint Creek Generating Station (Unit No. 1)	50.0	94,261	2,494	93,887	756
Pirkey Generating Station (Unit No. 1)	85.9	459,513	10,447	456,730	2,373
Total		$ 791,715	$ 16,770	$ 788,358	$ 5,688
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8%	$ 39,656	$ 321	$ 39,464	$ 271
STP Generation Station (Units No. 1 and 2)	0.0	-	-	2,386,961	2,144
Total		$ 39,656	$ 321	$ 2,426,425	$ 2,415
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7%	$ 288,934	$ 2,165	$ 287,198	$ 1,418

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets. STP was completed in May 2005. TCC owned 25.2% of STP at December 31, 2004.

The accumulated depreciation with respect to each Registrant Subsidiary's share of jointly-owned facilities is shown below:

	Year Ended December 31,	
	2005	2004
Company	(in thousands)	
CSPCo	$ 497,548	$ 464,136
PSO	54,401	52,679
SWEPCo	512,742	491,269
TCC (a)	19,765	991,410
TNC	117,963	110,763

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each Registrant Subsidiary follows:

Quarterly Periods Ended:	**AEGCo**	**APCo**	**CSPCo**	**I&M**	**KPCo**
			(in thousands)		
March 31, 2005					
Operating Revenues	$ 66,546	$ 557,695	$ 367,133	$ 457,559	$ 128,060
Operating Income	3,195	92,359	78,667	72,890	21,083
Income Before Cumulative Effect of Accounting Changes	2,516	46,672	47,468	39,669	9,885
Net Income	2,516	46,672	47,468	39,669	9,885
June 30, 2005					
Operating Revenues	$ 65,082	$ 497,102	$ 359,990	$ 457,560	$ 122,709
Operating Income	2,340	53,752	63,558	69,589	9,743
Income Before Cumulative Effect of Accounting Changes	2,073	24,213	34,651	35,593	2,446
Net Income	2,073	24,213	34,651	35,593	2,446
September 30, 2005					
Operating Revenues	$ 69,640	$ 570,122	$ 454,568	$ 515,079	$ 143,996
Operating Income	2,912	79,477	65,604	100,754	18,223
Income Before Cumulative Effect of Accounting Changes	2,239	37,372	34,225	53,012	7,727
Net Income	2,239	37,372	34,225	53,012	7,727
December 31, 2005					
Operating Revenues	$ 69,487	$ 551,354	$ 360,641	$ 462,404	$ 136,578
Operating Income	2,454	57,800	35,051	43,427	11,782
Income Before Cumulative Effect of Accounting Changes	1,867	27,575	21,455	18,578	751
Net Income	1,867	25,319	20,616	18,578	751

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2005					
Operating Revenues	$ 655,154	$ 253,082	$ 247,211	$ 201,357	$ 118,907
Operating Income	151,434	7,113	29,163	30,284	15,817
Income Before Cumulative Effect of Accounting Changes	99,483	505	12,205	1,137	7,394
Net Income	99,483	505	12,205	1,137	7,394
June 30, 2005					
Operating Revenues	$ 650,999	$ 286,602	$ 332,851	$ 202,326	$ 114,704
Operating Income	123,901	32,435	37,363	42,922	20,160
Income Before Cumulative Effect of Accounting Changes	71,481	18,570	19,304	28,368	12,004
Net Income	71,481	18,570	19,304	28,368	12,004
September 30, 2005					
Operating Revenues	$ 687,140	$ 432,633	$ 474,283	$ 203,365	$ 126,097
Operating Income	99,437	85,387	88,135	63,399	36,924
Income Before Cumulative Effect of Accounting Changes	56,408	48,654	49,731	40,476	22,304
Net Income	56,408	48,654	49,731	40,476	22,304
December 31, 2005					
Operating Revenues	$ 641,256	$ 331,761	$ 351,034	$ 186,198	$ 99,180
Operating Income (Loss)	50,715	(6,919)	5,876	40,676	3,798
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	23,047	(9,836)	(6,050)	(19,209)	(226)
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	-	-	-	(224,551)	-
Net Income (Loss)	18,472	(9,836)	(7,302)	(243,760)	(8,698)

(a) See "Extraordinary Items" section of Note 2 and "Texas Restructuring" section of Note 6 for discussions of the extraordinary loss booked in the fourth quarter of 2005.

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2004					
Operating Revenues	$ 55,282	$ 530,454	$ 365,395	$ 430,411	$ 114,579
Operating Income	2,175	128,656	82,888	85,259	25,282
Income Before Cumulative Effect of Accounting Changes	1,827	65,336	45,119	43,008	11,611
Net Income	1,827	65,336	45,119	43,008	11,611
June 30, 2004					
Operating Revenues	$ 56,348	$ 466,750	$ 358,757	$ 423,060	$ 106,891
Operating Income	2,026	63,547	60,001	57,967	12,564
Income Before Cumulative Effect of Accounting Changes	1,506	21,826	30,755	27,030	4,068
Net Income	1,506	21,826	30,755	27,030	4,068
September 30, 2004					
Operating Revenues	$ 65,303	$ 486,041	$ 391,612	$ 462,641	$ 113,785
Operating Income	2,990	77,988	90,359	94,636	13,968
Income Before Cumulative Effect of Accounting Changes	2,404	38,459	52,570	51,548	6,160
Net Income	2,404	38,459	52,570	51,548	6,160
December 31, 2004					
Operating Revenues	$ 64,855	$ 474,601	$ 332,161	$ 425,373	$ 113,706
Operating Income	2,939	58,370	25,331	31,697	11,525
Income Before Cumulative Effect of Accounting Changes	2,105	27,494	11,814	11,636	4,066
Net Income	2,105	27,494	11,814	11,636	4,066

Quarterly Periods Ended:		OPCo		PSO		SWEPCo		TCC		TNC
						(in thousands)				
March 31, 2004										
Operating Revenues	$	604,165	$	207,267	$	236,537	$	297,584	$	116,945
Operating Income (Loss)		155,999		(6,938)		20,544		73,062		25,870
Income (Loss) Before Cumulative Effect of Accounting Changes		80,164		(9,003)		5,021		29,404		13,096
Net Income (Loss)		80,164		(9,003)		5,021		29,404		13,096
June 30, 2004										
Operating Revenues	$	577,282	$	231,899	$	269,325	$	280,561	$	117,734
Operating Income		87,439		18,632		55,671		25,176		16,730
Income (Loss) Before Cumulative Effect of Accounting Changes		38,783		7,391		27,946		(341)		7,751
Net Income (Loss)		38,783		7,391		27,946		(341)		7,751
September 30, 2004										
Operating Revenues	$	603,054	$	356,741	$	331,815	$	359,440	$	160,885
Operating Income		102,179		71,096		83,640		87,028		30,296
Income Before Cumulative Effect of Accounting Changes		50,685		38,980		47,209		43,012		16,853
Net Income		50,685		38,980		47,209		43,012		16,853
December 31, 2004										
Operating Revenues	$	588,224	$	251,913	$	253,395	$	275,264	$	157,894
Operating Income		73,922		16		19,384		58,815		18,175
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes (a)		40,484		174		9,281		222,581		9,959
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (b)		-		-		-		(120,534)		-
Net Income		40,484		174		9,281		102,047		9,959

(a) Carrying costs income on stranded cost recovery of $302 million was recorded in the fourth quarter of 2004.

(b) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarter of 2004.

For each of the Registrant Subsidiaries, (excluding TCC for 2004 and 2005) there were no significant, nonrecurring events in the fourth quarter of 2005 or 2004.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the Registrant Subsidiaries through intercompany notes. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The Registrant Subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from AEP.

Dividend Restrictions

Under regulatory orders, the Registrant Subsidiaries can only pay dividends out of retained or current earnings.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. AEP does not have an ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables, and accelerate cash collections.

AEP Credit's sale of receivables agreement expires August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit.

Budgeted Construction Expenditures

Construction expenditures for Registrant Subsidiaries for 2006 are:

Company	Projected Construction Expenditures (in millions)
AEGCo	$ 14
APCo	943
CSPCo	343
I&M	311
KPCo	100
OPCo	1,070
PSO	279
SWEPCo	288
TCC	278
TNC	73

Significant Factors

Integration Gasification Combined Cycle (IGCC) Power Plants

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSP. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover, or refund, in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. As of December 31, 2005, we have deferred $7 million of pre-construction IGCC costs for the Ohio companies. These costs primarily relate to an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process.

In January 2006, APCo filed an application with the WVPSC seeking authority to construct a 600MW IGCC electric generating unit in West Virginia. If built, the unit would be located next to APCo's Mountaineer Plant.

Pension and Postretirement Benefit Plans

AEP maintains qualified, defined benefit pension plans (Qualified Plans or Pensions Plans), which cover a substantial majority of nonunion and certain union associates, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. AEP also sponsors other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic cost (credit) for AEP's Pension Plans and Postretirement Plans:

	2005	2004
	(in millions)	
Net Periodic Cost:		
Pension Plans	$ 61	$ 40
Postretirement Plans	109	141
Assumed Rate of Return:		
Pension Plans	8.75%	8.75%
Postretirement Plans	8.37%	8.35%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as its 10-year average return, for the period ended December 2005, of approximately 10%. AEP anticipates that the investment managers employed for the Plans will continue to generate long-term returns averaging 8.50%.

The expected long-term rate of return on the Plans' assets is based on AEP's targeted asset allocation and its expected investment returns for each investment category. AEP's assumptions are summarized in the following table:

	Pension		Other Postretirement Benefit Plans		
	2005 Actual Asset Allocation	2006 Target Asset Allocation	2005 Actual Asset Allocation	2006 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	66%	70%	68%	66%	10.00%
Fixed Income	25%	28%	30%	31%	5.25%
Cash and Cash Equivalents	9%	2%	2%	3%	3.50%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. Because of a $320 million discretionary contribution to the Qualified Plans at the end of 2005, the actual asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced back to the target allocation in January 2006. AEP believes that 8.50% is a reasonable long-term rate of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 7.76% and 12.90% for the twelve months ended December 31, 2005 and 2004, respectively. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2005, AEP had cumulative losses of approximately $37 million, which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2005 under this method was 5.50% for the Pension Plans and 5.65% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Plans' assets of 8.50%, a discount rate of 5.50% and various other assumptions, AEP estimates that the pension costs for all pension plans will approximate $73 million, $76 million and $56 million in 2006, 2007 and 2008, respectively. AEP estimates Postretirement Plan costs will approximate $99 million, $102 million and $97 million in 2006, 2007 and 2008, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 0.5% basis point change to selective actuarial assumptions are in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Combined Management's Discussion and Analysis of Registrant Subsidiaries.

The value of AEP's Pension Plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The Qualified Plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.2 billion at December 31, 2005 from $1.1 billion at December 31, 2004. The Postretirement Plans paid $118 million in benefits to plan participants during 2005.

For AEP's underfunded pension plans, the accumulated benefit obligation in excess of plan assets was $81 million and $474 million at December 31, 2005 and 2004, respectively. While AEP's non-qualified pension plans are unfunded, the qualified pension plans are fully funded as of December 31, 2005.

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

AEP made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet the goal of fully funding all Qualified Plans by the end of 2005.

Certain pension plans AEP sponsors and maintains contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. AEP believes that the defined benefit pension plans it sponsors and maintains are in compliance with the applicable requirements of such laws.

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability even for fully funded pension and postretirement benefit plan, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 smoothing deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net of tax accumulated other comprehensive income reduction to common equity. We cannot predict the effects of the final rule or its effective date.

Litigation

See discussion of the Environmental Litigation under "Environmental Matters."

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

The Registrant Subsidiaries have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants; and
- Possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change.

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality, and control mobile and stationary sources of air emissions. The major CAA programs affecting power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reductions of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA is currently reconsidering certain aspects of the final CAIR, and the rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which the Registrant

Subsidiaries' power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program has encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. The Registrant Subsidiaries continue to meet their obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and-trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the "Regional Haze" program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above will require significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Management's estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and selected compliance alternatives. In short, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

APCo, CSPCo, KPCo and OPCo installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at their power plants over the past several years to comply with NO_x requirements in various SIPs. Additional NO_x requirements associated with CAIR and CAMR will result in additional investments between 2006 and 2010, estimated to be $191 million, including completion of SCRs on an additional 1900 MW of capacity. The amount of additional investment per Registrant Subsidiary follows:

	Estimated Investment (in millions)
APCo	$ 2
CSPCo	42
OPCo	137
PSO	1
SWEPCo	9

The Registrant Subsidiaries are complying with Acid Rain Program SO_2 requirements by installing scrubbers, other controls, and using alternate fuels. The Registrant Subsidiaries also use SO_2 allowances received through Acid Rain Program allocations, purchased at the annual Federal EPA auction, and purchased in the market. Decreasing allowance allocations, diminishing SO_2 allowance bank, and increasing allowance costs will require installation additional controls on the Registrant Subsidiaries' power plants. In addition, under CAIR and CAMR the Registrant Subsidiaries will be required to install additional controls by 2010. The Registrant Subsidiaries plan to install by 2010 additional scrubbers on 8,700 MW to comply with current, CAIR and CAMR requirements. The following table shows the estimated costs for additional scrubbers from 2006 to 2010 by Registrant Subsidiary:

	Cost of Additional Scrubbers (in millions)
APCo	$ 1,251
CSPCo	234
KPCo	308
OPCo	979
SWEPCo	18

The Registrant Subsidiaries will also incur additional operation and maintenance expenses during 2006 and subsequent years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, the Registrant Subsidiaries expect to incur additional costs for pollution control technology retrofits totaling approximately $1 billion between 2011 and 2020. The cost are highly uncertain due to the uncertainty associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on each unit, (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. Management cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

The Registrant Subsidiaries will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). The Registrant Subsidiaries should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Clean Water Act Regulation

In July 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for the Registrant Subsidiaries plants. Any capital costs incurred to meet these standards will likely be incurred between 2008 and 2010. The Registrant Subsidiaries are required to undertake site-specific studies and may propose site-specific compliance or mitigation measures that could significantly change this estimate. These studies are currently underway, and the rule has been challenged in the courts. The following table shows the investment amount per Registrant Subsidiary.

	Estimated Compliance Investments (in millions)
APCo	$ 21
CSPCo	19
I&M	118
OPCo	31

Potential Regulation of CO_2 Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in November 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none has passed either house of Congress.

The Federal EPA has stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. While mandatory requirements to reduce CO_2 emissions at power plants do not appear to be imminent, the AEP System participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed against other nonaffiliated utilities in 1999 and 2000. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

Courts that have considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, have reached different conclusions. Similarly, courts that have considered whether the activities at issue increased emissions from the power plants have reached different results. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability the Registrant Subsidiaries might have for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the court. If the Registrant Subsidiaries do not prevail, management believes the Registrant Subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If the Registrant Subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Other Environmental Concerns

Management performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the Registrant Subsidiaries are managing other environmental concerns, which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and
- changes in the estimate or different estimates that could have been selected could have a material effect on results of operations or financial condition.

Management has discussed the development and selection of its critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee has reviewed the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

The sections that follow present information about the Registrant Subsidiaries' most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required – The consolidated financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, AEGCo and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC) reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recognized for the economic effects of regulation by matching the timing of expense recognition with the recovery of such expense in regulated revenues. Likewise, income is matched with the regulated revenues from our customers in the same accounting period. Regulatory liabilities are also recorded for refunds, or probable refunds, to customers that have not yet been made.

Assumptions and Approach Used – When regulatory assets are probable of recovery through regulated rates, they are recorded as assets on the balance sheet. Regulatory assets are tested for probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used – A change in the above assumptions may result in a material impact on the results of operations. Refer to Note 5 of the Notes to Financial Statements of Registrant Subsidiaries for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required – Revenues are recognized and recorded when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is alsoestimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. Accrued unbilled revenue as of December 31, 2005 and 2004 is reflected as Accrued Unbilled Revenues on the accompanying Registrant Subsidiaries' Balance Sheets.

Unbilled electric utility revenues included in Revenue for the years ended December 31 were as follows:

	2005	2004	2003
		(in thousands)	
APCo	$ 14,024	$ 18,206	$ 1,876
CSPCo	(5,404)	283	(5,881)
I&M	1,783	(2,942)	10,722
KPCo	1,105	3,833	(448)
OPCo	14,689	(2,793)	(18,502)
PSO	494	2,789	984
SWEPCo	606	1,814	(6,996)
TCC	(164)	(1,579)	4,636
TNC	1,250	(1,160)	1,834

Assumptions and Approach Used – The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation determines factors that limit the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are then statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

In addition, an annual comparison to a load research estimate is performed for the AEP East companies. The annual load research study, based on a sample of accounts, is an additional verification of the unbilled estimate. The unbilled estimate is also adjusted annually, if necessary, for significant differences from the load research estimate.

Effect if Different Assumptions Used – Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required – Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used – APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided for in the original documentation related to hedge accounting.

Effect if Different Assumptions Used – There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required – In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," long-lived assets are evaluated as necessary for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. These evaluations of long-lived assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For nonregulated assets, an impairment charge would be recorded as a charge against earnings.

Assumptions and Approach Used – The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales, or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

fect if Different Assumptions Used – In connection with the evaluation of long-lived assets in accordance with the quirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have en used in the applied valuation techniques. In cases of impairment as described in Note 10 of the Notes to nancial Statements of Registrant Subsidiaries, the best estimate of fair value was made using valuation methods ised on the most current information at that time. Certain Registrant Subsidiaries have been divesting certain eneration assets and their sales values can vary from the recorded fair value as described in Note 10 of the Notes to inancial Statements of Registrant Subsidiaries. Fluctuations in realized sales proceeds versus the estimated fair alue of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent arket conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of e benefits of the transaction.

ension and Other Postretirement Benefits

ature of Estimates Required – APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC sponsor ension and other retirement and postretirement benefit plans in various forms covering all employees who meet igibility requirements. These benefits are accounted for under SFAS 87, "Employers' Accounting For Pensions" nd SFAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions," respectively. See Note 1 of the Notes to Financial Statements of Registrant Subsidiaries for more information regarding costs and ssumptions for employee retirement and postretirement benefits. The measurement of pension and postretirement bligations, costs and liabilities is dependent on a variety of assumptions used by actuaries and APCo, CSPCo, &M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The actuarial assumptions used may differ materially from ctual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter ife spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These ifferences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

ssumptions and Approach Used – The critical assumptions used in developing the required estimates include the ollowing key factors:

- discount rate
- expected return on plan assets
- health care cost trend rates
- rate of compensation increases

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used – The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
		(in millions)		
Effect on December 31, 2005 Benefit Obligations:				
Discount Rate	$ (198)	$ 207	$ (116)	$ 124
Salary Scale	30	(30)	4	(4)
Cash Balance Crediting Rate	(16)	17	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	112	(106)
Effect on 2005 Periodic Cost:				
Discount Rate	(10)	10	(10)	10
Salary Scale	6	(5)	1	(1)
Cash Balance Crediting Rate	3	(2)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(17)
Expected Return on Assets	(18)	18	(5)	5

New Accounting Pronouncements

In December 2004, the FASB issued SFAS 123R "Share-Based Payment." SFAS 123R requires entitie recognize compensation expense in an amount equal to the fair value of share-based payments granted to employe In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's vie on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SE staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FAS issued three FASB Staff Positions (FSP) during 2005 that provided additional implementation guidance. T Registrant Subsidiaries applied the principles of SAB 107 and the applicable FSPs in conjunction with th adoption of SFAS 123R. The Registrant Subsidiaries implemented SFAS 123R in the first quarter of 2006 using t modified prospective method. This method required recording compensation expense for all awards granted af the time of adoption and recognition of the unvested portion of previously granted awards that remain outstanding the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair val of the equity award. Implementation of SFAS 123R did not materially affect results of operations, cash flows financial condition.

The Registrant Subsidiaries adopted FASB Interpretation No. 47 "Accounting for Conditional Asset Retireme Obligations" (FIN 47) during the fourth quarter of 2005. The Registrant Subsidiaries completed a review of the FIN 47 conditional ARO and concluded that they have legal liabilities for asbestos removal and disposal in gener building and generating plants. The cumulative effect of certain retirement costs for asbestos removal related regulated operations was generally charged to a regulatory liability. Certain Registrant Subsidiaries recorded a unfavorable cumulative effect for their nonregulated operations related to asbestos removal as follows:

	Cumulative Effect	
	Pretax Income (Loss)	Net of Tax Income (Loss)
	(in millions)	
APCo	$ (3.5)	$ (2.3)
CSPCo	(1.3)	(0.8)
OPCo	(7.0)	(4.6)
SWEPCo	(1.9)	(1.3)
TNC	(13.0)	(8.5)

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty" focuses on tw inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combine under APB Opinion No. 29, "Accounting for Nonmonetary Transactions" if they were entered in contemplation o one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value i an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fai value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within th same line of business should be valued at the carrying amount of the inventory transferred. This issue will b implemented beginning April 1, 2006 and is not expected to have a material impact on the financial statements.

UNITED STATES
FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20549

FORM 60

ANNUAL REPORT

FOR THE PERIOD

Beginning January 1, 2005 and Ending December 31, 2005

TO THE

FEDERAL ENERGY REGULATORY COMMISSION

OF

AMERICAN ELECTRIC POWER SERVICE CORPORATION
(Exact Name of Reporting Company)

A Subsidiary Service Company
("Mutual" or "Subsidiary")

Date of Incorporation December 17, 1937 If not Incorporated, Date of Organization ________.

State or Sovereign Power under which Incorporated or Organized New York

Location of Principal Executive Offices of Reporting Company Columbus, Ohio

Name, title, and address of officer to whom correspondence concerning this report should be addressed:

S. S. Bennett	Assistant Controller	1 Riverside Plaza Columbus, Ohio 43215
(Name)	(Title)	(Address)

Name of Principal Holding Company under which Reporting Company is organized:

AMERICAN ELECTRIC POWER COMPANY, INC.

INSTRUCTIONS FOR USE OF FORM 60

1. Timing of Filing

   On or before the first day of May in each calendar year, each mutual service company and each subsidiary service company shall file with Commission an annual report on Form 60 and in accordance with the Instructions for that form.

2. Number of Copies

   Each annual report shall be filed in duplicate. The company should prepare and retain at least one extra copy for itself in case correspondence with reference to the report becomes necessary.

3. Period Covered by Report

   The first report filed by the company shall cover the period from the date the Uniform System of Accounts was required to be made effective as to that company to the end of that calendar year. Subsequent reports should cover a calendar year

4. Report Format

   Reports shall be submitted on the forms prepared by the Commission. If the space provided on any sheet of such form is inadequate, additional sheets may be inserted of the same size as a sheet of the form or folded to each size.

5. Money Amounts Displayed

   All money amounts required to be shown in financial statements may be expressed in whole dollars, in thousands of dollars or in hundred thousands of dollars, as appropriate and subject to provisions of Regulation S-X (210.3-01)

6. Deficits Displayed

   Deficits and other like entries shall be indicated by the use of either brackets or a parenthesis with corresponding reference in footnotes (Regulation S-X, 210.3-01(c))

7. Major Amendments or Corrections

   Any company desiring to amend or correct a major omission or error in a report after it has been filed with the Commission shall submit an amended report including only those pages, schedules and entries that are to be amended or corrected. A cover letter shall be submitted requesting the Commission to incorporate the amended report changes and shall be signed by a duly authorized officer of the company.

8. Definitions

   Definitions contained in Instruction 01-8 to the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, Public Utility Holding Act of 2005, shall be applicable to words or terms used specifically within this Form 60.

9. Organization Chart

   The Service Company shall submit with each annual report a copy of its current organization chart.

10. Methods of Allocation

The Service Company shall submit with each annual report a listing of the currently effective methods of allocation being used by the service company and on file and approved previously by the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935.

11. Annual Statement of Compensation for Use of Capital Billed

The service company shall submit with each annual report a copy of the annual statement supplied to each associate company in support of the amount of compensation for use of capital billed during the calendar year.

12. Collection of Information

The information requested by this form is being collected under authority of the Public Utility Holding Act of 2005. The Commission estimates that it will take each respondent thirteen and one-half (13.5) hours to respond to this collection of information. A response to this form is mandatory. The information on this form will not be kept confidential. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless a currently valid OMB control number is displayed.

13. Where to File

File Form 60 at the following address:

Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	ASSETS AND OTHER DEBITS	AS OF DECEMBER 31 2005	2004
	SERVICE COMPANY PROPERTY		
101-106	Service company property (Schedule II)	$ 314,913	$ 295,186
107	Construction work in progress (Schedule II)	12,592	9,774
	Total Property	327,505	304,960
108-111	Less: Accumulated provision for depreciation and amortization of service company property (Schedule III)	165,247	146,888
	Net Service Company Property	162,258	158,072
	INVESTMENTS		
123	Investments in associate companies (Schedule IV)	-	-
124	Other investments (Schedule IV)	123,961	118,579
	Total Investments	123,961	118,579
	CURRENT AND ACCRUED ASSETS		
131	Cash	21,528	9,540
134	Special deposits	36	29
135	Working funds	120	114
136	Temporary cash investments (Schedule IV)	-	-
141	Notes receivable	-	-
143	Accounts receivable	5,311	5,655
144	Accumulated provision for uncollectible accounts	-	-
145	Advances to Affiliates	-	29,178
146	Accounts receivable from associate companies (Schedule V)	189,649	177,184
152	Fuel stock expenses undistributed (Schedule VI)	-	-
154	Materials and supplies	-	-
163	Stores expense undistributed (Schedule VII)	-	-
165	Prepayments	215,239	3,156
174	Miscellaneous current and accrued assets (Schedule VIII)	3	-
	Total Current and Accrued Assets	431,886	224,856
	DEFERRED DEBITS		
181	Unamortized debt expense	1,281	1,708
182	Regulatory Assets	115	425
184	Clearing Accounts	3	-
186	Miscellaneous deferred debits (Schedule IX)	7,797	2,631
188	Research, development, or demonstration expenditures (Sch. X)	-	-
190	Accumulated deferred income taxes	104,824	117,256
	Total Deferred Debits	114,020	122,020
	TOTAL ASSETS AND OTHER DEBITS	$ 832,125	$ 623,527

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	LIABILITIES AND PROPRIETARY CAPITAL	AS OF DECEMBER 31 2005	2004
	PROPRIETARY CAPITAL		
201	Common stock issued (Schedule XI)	$ 1,350	$ 1,350
211	Miscellaneous paid-in-capital (Schedule XI)	100	100
215	Appropriated retained earnings	-	-
216	Unappropriated retained earnings	-	-
219	Accumulated other comprehensive income (Schedule XI)	(16,852)	(76,469)
	Total Proprietary Capital	(15,402)	(75,019)
	LONG-TERM DEBT		
223	Advances from associate companies (Schedule XII)	50,000	50,000
224	Other long-term debt (Schedule XII)	38,000	40,000
225	Unamortized premium on long-term debt	-	-
226	Unamortized discount on long-term debt-debit	-	-
	Total Long-Term Debt	88,000	90,000
	OTHER NONCURRENT LIABILITIES		
227	Obligations under capital leases - Noncurrent	52,422	46,849
228.2	Accumulated Provision for Injuries and Damages	159	300
228.3	Accumulated Provision for Pensions and Benefits	180,751	171,358
	Total Other Noncurrent Liabilities	233,332	218,507
	CURRENT AND ACCRUED LIABILITIES		
231	Notes payable	-	-
232	Accounts payable	22,526	17,030
233	Notes payable to associate companies (Schedule XIII)	9,896	-
234	Accounts payable to associate companies (Schedule XIII)	139,116	117,944
236	Taxes accrued	15,794	553
237	Interest accrued	4,832	4,347
241	Tax collections payable	514	648
242	Miscellaneous current and accrued liabilities (Schedule XIII)	209,613	157,467
243	Obligations under capital leases - Current	26,408	20,253
	Total Current and Accrued Liabilities	428,699	318,242
	DEFERRED CREDITS		
253	Other deferred credits	11,003	8,655
254	Regulatory Liabilities	7,809	9,565
255	Accumulated deferred investment tax credits	648	699
	Total Deferred Credits	19,460	18,919
282	**ACCUMULATED DEFERRED INCOME TAXES**	78,036	52,878
	TOTAL LIABILITIES AND PROPRIETARY CAPITAL	$ 832,125	$ 623,527

Note: Account 223, Advances from associate companies, includes $50,000,000 due May 15, 2006 at December 31, 2005. Account 224, Other long term debt, includes $2,000,000 due within one year at December 31, 2005 and $2,000,000 at December 31, 2004 (See note 8, Schedule XIV).

ANNUAL REPORT of American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	14,347	(784)	(1,270)	-	12,293
304 Land and Land Rights	4,184	-	-	-	4,184
305 Structures and Improvements	150,741	200	(1,089)	(43)	149,809
306 Leasehold Improvements	5,285	91	-	-	5,376
307 Equipment (2)	16,132	41	-	-	16,173
308 Office Furniture and Equipment	8,676	-	-	-	8,676
309 Automobiles, Other Vehicles and Related Garage Equipment	-	-	-	-	-
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Property: (3)					
Owned	182	60	-	-	242
Leased	95,639	-	-	22,521	118,160
SUB-TOTALS (A)	295,186	(392)	(2,359)	22,478	314,913
107 Construction Work in Progress (4)	9,774	2,818	-	-	12,592
TOTALS	$ 304,960	$ 2,426	$ (2,359)	$ 22,478	$ 327,505

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

FOOTNOTES

(1) *Provide an explanation of those changes considered material:*

311 Other Property - Change in Leased property reported as a net number. The majority of the additions relates to IT equipment, including servers.

(2) *Subaccounts are required for each class of equipment owned. The service company shall provide a listing by subaccount of equipment additions during the year and the balance at the close of the year:*

Subaccount Description	Additions	Balance At Close Of Year
Account 307 - Equipment:		
Data Processing Equipment	$ -	$ 10,679
Communications Equipment	-	3,088
Laboratory Equipment	41	2,406
TOTALS	$ 41	$ 16,173

(3) *Describe Other Service Company Property:*

Account 311 includes leased assets at December 31, 2005, of $118,159,975 which have been capitalized in accordance with FASB Statement Nos. 13 and 71 and other owned assets at December 13, 2005, of $242,000.

(4) *Describe Construction Work in Progress*:

Capitalized Software	$ 2,091
General and Miscellaneous Equipment	5,191
Inprovements to Office Buildings - Owned and Leased	5,310
TOTALS	$ 12,592

SCHEDULE III - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	11,016	1,500	(1,270)	-	11,246
304 Land and Land Rights	-	-	-	-	-
305 Structures and Improvements	81,310	6,666	(1,089)	-	86,887
306 Leasehold Improvements	2,500	-	-	1,715	4,215
307 Equipment	12,947	26	-	-	12,973
308 Office Furniture and Equipment	7,191	7	-	-	7,198
309 Automobiles, Other Vehicles and Related Garage Equipment	-	-	-	-	-
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Service Company Property:					
Owned	113	-	-	-	113
Leased	28,404	-	-	10,926	39,330
SUB-TOTALS	143,481	8,199	(2,359)	12,641	161,962
108 Retirement Work in Progress	3,407	(181)	-	59	3,285
TOTALS	$ 146,888	$ 8,018	$ (2,359)	$ 12,700	$ 165,247

(1) Provide an explanation of those changes considered material:

306 Leasehold Improvements - Change due to a reserve adjustment for Tulsa Williams Tower 2.
311 Other Property - Change in Leased Assets reported as a net number. The majority of the additions relates to IT equipment, including servers.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE IV - INVESTMENTS
(In Thousands)

Instructions: Complete the following schedule concerning investments.

Under Account 124 "Other Investments", state each investment separately, with description, including the name of issuing company, number of shares or principal amount, etc.

Under Account 136, "Temporary Cash Investments", list each investment separately.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 123 - Investment in Associate Companies		
Investment in Common Stock of Subs	$ -	$ -
SUB-TOTALS	-	-
Account 124 - Other Investments		
Cash Surrender Value of Life Insurance Policies		
(net of policy loans and accrued interest)	19,717	23,778
Umbrella Trust	82,271	84,664
COLI Tax and Interest	16,591	15,519
SUB-TOTALS	118,579	123,961
Account 136 - Temporary Cash Investments	-	-
SUB-TOTALS	-	-
TOTALS	$ 118,579	$ 123,961

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 146 - Accounts Receivable from Associate Companies		
Account Balances by Associate Company		
AEP Acquisition L.L.C.	$ 3	$ -
AEP C&I Company LLC	3	1
AEP Coal Co.	9	79
AEP Coal Marketing LLC	32	23
AEP Communications, Inc.	2	222
AEP Communications, LLC	88	-
AEP Credit, Inc.	43	36
AEP Delaware Investment Company	2	-
AEP Delaware Investment Company II	1	-
AEP Desert Sky LP, LLC	55	38
AEP Desert Sky GP, LLC	6	10
AEP Elmwood LLC	21	43
AEP Emissions Marketing, LLC	1	-
AEP EmTech LLC	146	-
AEP Energy Services Gas Holding Company	96	21
AEP Energy Services Gas Holdings II LLC	7	-
AEP Energy Services Investments, Inc.	159	-
AEP Energy Services Limited	77	337
AEP Energy Services, Inc.	1,194	366
AEP Gas Power GP, LLC	3	2
AEP Generating Company	178	187
AEP Holdings II CV	-	31
AEP Investments, Inc.	20	102
AEP Kentucky Coal, LLC	543	-
AEP MEMCo LLC	94	184
AEP Nonutility Funding LLC	1	29
AEP Power Marketing, Inc.	2	1
AEP Pro Serv, Inc.	487	243
AEP Resources Australia Holdings Pty, Ltd	1	-

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
AEP Resources, Inc.	$ 2,486	$ 173
AEP System Pool	3,512	3,761
AEP T & D Services, LLC	50	71
AEP Texas Central Company	10,466	12,791
AEP Texas Commercial & Industrial Retail GP, LLC	2	1
AEP Texas Commercial & Industrial Retail Limited Partnership	39	13
AEP Texas North Company	3,850	4,273
AEP Texas POLR, LLC	1	-
AEP Utilities Inc.	26	24
AEP Utility Funding LLC	137	8
AEP Wind Energy, LLC	141	37
AEP Wind Holding, LLC	246	285
AEPR Ohio, LLC	254	-
American Electric Power Company, Inc.	782	924
Appalachian Power Company	43,262	45,783
Blackhawk Coal Company	1	1
C3 Communications, Inc.	13	-
Cardinal Operating Company	1,684	1,688
Colomet, Inc.	1	1
Columbus Southern Power Company	34,822	40,689
Conesville Coal Preparation Company	24	53
CSW Energy Services, Inc.	54	5
CSW Energy, Inc.	333	206
CSW International, Inc.	4	2
CSW Services International Inc.	8	5
CSW Sweeny LP II, Inc.	-	158
Desert Sky Wind Farm LP	79	25
Diversified Energy Contractors Company, LLC	5	5
Dolet Hills Lignite Company, LLC	206	118
Houston Pipe Line Company LP	534	-

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
HPL Storage, Inc	$ -	$ 1
Indiana Michigan Power Company	17,165	17,214
Kentucky Power Company	8,066	8,029
Kingsport Power Company	389	506
Mutual Energy L.L.C.	5	1
Mutual Energy SWEPCO L.P.	7	30
Ohio Power Company	26,861	23,108
POLR Power, L.P.	2	-
Public Service Company of Oklahoma	8,838	13,780
REP General Partner L.L.C.	29	1
REP Holdco Inc.	39	10
Snowcap Coal Company, Inc.	8	-
Southwestern Electric Power Company	8,792	13,104
Sweeny Cogeneration LP	28	-
Trent Wind Farm LP	46	18
United Sciences Testing, Inc.	133	282
Ventures Lease Co., LLC	112	8
Wheeling Power Company	368	502
TOTALS	$ 177,184	$ 189,649

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	TOTAL PAYMENTS
Analysis of Convenience or Accomodation Payments by Company:	
AEP Coal Co.	$ 4
AEP Communications, Inc.	1
AEP Communications, LLC	273
AEP Credit, Inc.	439
AEP EmTech LLC	17
AEP Energy Services Gas Holding Company	410
AEP Energy Services Limited	157
AEP Generating Company	295
AEP Investments, Inc.	1
AEP MEMco LLC	13
AEP Pro Serv, Inc.	59
AEP Resources, Inc.	188
AEP Texas Central Company	17,814
AEP Texas North Company	8,511
AEP Utilities, Inc.	12
AEPES General and Administrative	589
American Electric Power Company, Inc.	1,782
Appalachian Power Company	346,433
C3 Communications, Inc.	1
Cardinal Operating Company	216
Columbus Southern Power Company	183,143
Conesville Coal Preparation Company	13
CSW Energy, Inc.	359
CSW Energy Services, Inc.	4
CSW Sweeny LP II, Inc.	158
Desert Sky Windfarm LP	48
Dolet Hills Lignite Company LLC	62
Franklin Real Estate Company	8
Houston Pipe Line Company LP	20
Indiana Michigan Power Company	419,582

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	TOTAL PAYMENTS
Kentucky Power Company	$ 80,646
Kingsport Power Company	325
Mutual Energy SWEPCO L.P.	31
Ohio Power Company	709,152
Public Service Company of Oklahoma	29,674
Southwestern Electric Power Company	32,917
Sweeny Cogenerating LP	2
Trent Wind Farm LP	37
United Sciences Testing, Inc.	56
Wheeling Power Company	685
TOTAL	$ 1,834,137

ANNUAL REPORT OF American Electric Power Service Corporation

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SCHEDULE VI - FUEL STOCK EXPENSES UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company. Under the section headed "Summary" listed below give an overall report of the fuel functions performed by the service company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 152 - Fuel Stock Expenses Undistributed			
Associate Companies:			
AEP MEMCo LLC	$ 5	$ (2)	$ 3
AEP Texas Central Company	7	6	13
AEP Texas North Company	72	44	116
AEPES General and Administrative	5	2	7
Appalachian Power Company	2,010	948	2,958
Cardinal Operating Company	551	257	808
Columbus Southern Power Company	925	439	1,364
Indiana Michigan Power Company	1,388	650	2,038
Kentucky Power Company	332	157	489
Ohio Power Company	2,628	1,267	3,895
Public Service Company of Oklahoma	954	433	1,387
Snowcap Coal Company, Inc.	9	2	11
Southwestern Electric Power Company	1,829	877	2,706
AEPSC/Internal Support Costs	-	2	2
Subtotal	10,715	5,082	15,797
Nonassociate Companies	423	229	652
TOTAL Billable Balance Sheet Amounts	11,138	5,311	16,449
Less Amounts Billed	11,138	5,311	16,449
Net amount remaining on the Balance Sheet	$ -	$ -	$ -

Summary: The service company provides overall management of fuel supply and transportation procurement, as well as general administration.

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SCHEDULE VII - STORES EXPENSE UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 163 -Stores Expense Undistributed			
Associate Companies			
AEP Coal Marketing LLC	$ 5	$ 1	$ 6
AEP Communications, LLC	3	-	3
AEP Desert Sky LP, LLC	10	1	11
AEP Generating Company	24	2	26
AEP Investments, Inc.	2	-	2
AEP Nonutility Funding LLC	5	1	6
AEP Pro Serv, Inc.	2	-	2
AEP Resources, Inc.	22	1	23
AEP Texas Central Company	1,637	117	1,754
AEP Texas North Company	702	39	741
AEP Utilities, Inc.	1	1	2
AEP Utility Funding LLC	1	-	1
AEP Wind Holding, LLC	7	1	8
AEPES General and Administrative	67	5	72
American Electric Power Company, Inc.	41	3	44
Appalachian Power Company	3,040	307	3,347
Cardinal Operating Company	311	23	334
Columbus Southern Power Company	1,063	108	1,171
Conesville Coal Preparation Company	5	1	6
CSW Energy Services, Inc.	1	-	1
CSW Energy, Inc.	16	1	17
Indiana Michigan Power Company	1,831	172	2,003
Kentucky Power Company	499	52	551
Kingsport Power Company	42	5	47
Ohio Power Company	3,176	266	3,442
Public Service Company of Oklahoma	1,482	139	1,621
Rep Holdco Inc.	1	-	1
Southwestern Electric Power Company	1,465	114	1,579
United Sciences Testing, Inc,	1	-	1
Wheeling Power Company	66	6	72
AEPSC/Internal Support Costs	90	309	399
TOTAL Billable Balance Sheet Amounts	15,618	1,675	17,293
Less Amounts Billed	15,618	1,675	17,293
Net amount remaining on the Balance Sheet	$ -	$ -	$ -

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SCHEDULE VIII - MISCELLANEOUS CURRENT AND ACCRUED ASSETS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 174 - Miscellaneous Current and Accrued Assets		
Other	$ -	$ 3
TOTALS	$ -	$ 3

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SCHEDULE IX - MISCELLANEOUS DEFERRED DEBITS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped by class showing the number of items in each class.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 186 - Miscellaneous Deferred Debits		
Investigation Costs re New Generation Facilities	$ 803	$ 611
Accrued Labor Costs	914	7,186
Unbilled Charges	914	-
TOTALS	$ 2,631	$ 7,797

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SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES

(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION		AMOUNT
Account 188 - Research, Development, or Demonstration Expenditures		
General Activities:		
	2003 Distribution Resources Standards Management	$ 13
	Renew Energy Resources Program Management	15
	Amperion Power Line Carrier	18
	NAS Demonstration in Gahanna	30
	AEP Patent Review Process	31
	Competitive Technology Intelligence	34
	DTC Development and Demonstration	38
	PSerc/NREL Microgrid	65
	Supercap Cell Design & Optimization	67
	Supercap Project Management	70
	Renewable Energy Sources EPRI	70
	Distribution Resources Program Management	116
	DR Technologies - Assessment	121
	Occupational Health and Safety	121
	GSU Acoustic Emission Monitors	157
	EmTech Program Management	158
	Wireless & EMI Demos	190
	EPRI EMF Research	575
	PCS Development - Inverter/Converter	676
	Dolan Operations	753
	R&D Program Development	1,619
	5 items under $5,000	3
SUB-TOTAL		4,940
Nuclear:		
	Nuclear Asset Program Management	1,214
SUB-TOTAL		1,214
Steam Power:		
	Ash Pond SCR Ammonia Mitigation	(52)
	APTEC Advanced Ultrasonic Technology	10
	Picway Co-Firing	10
	Coal Industry Advisory Board	15
	MerCCIG	21
	Water Environment Research Foundation	29
	Generation Asset Program Management	29

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SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES
(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION		AMOUNT
Account 188 - Research, Development, or Demonstration Expenditures		
Steam Power (continued):		
	Muskingum River Biomass Co-fire	$ 32
	Midwest Regional Carbon Seques	33
	Grade 91 Tubing Remaining Life	50
	MIT Climate Change Program	50
	Enhancement of MECO Model - CO2	60
	Inspect CF in Waterwalls	70
	Climate Contingency Roadmap	75
	Mercury Deposition Modeling	75
	Conesville Sorbent Testing Facility	84
	Coal Utilization Research Council	93
	Generation EPRI Base	104
	Advanced Generation Program Management	140
	Geologic Feasibility of CO2 Dioxide	159
	Ohio River Ecological Research	221
	Environmental Controls Program	223
	FutureGen Project	405
	Generation EPRI Base Program	534
	General Mercury Science & Technology	647
	EPRI Environmental Control Program	925
	EPRI Environmental Science Program	3,474
	4 items under $5,000	11
SUB-TOTAL		7,527
Transmission and Distribution:		
	Dynamic Thermal Circuit Rating	6
	High Temp Low Sag Conductor	6
	CEA Life Cycle Mgmt of Station Equipment	7
	DSTAR Program 8	8
	AEP - USI Inclinometer	9
	Distribution System DR Demonstration	9
	Advanced Communications and Council	13
	CEA Transmission Line Interest	13
	PowerWorld Visualization Tools	14
	ABB CAT Reactor Synchronous Sw	17
	Blacksburg 69kV Underground Cable	19

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For the Year Ended December 31, 2005

SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES
(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION		AMOUNT
Account 188 - Research, Development, or Demonstration Expenditures		
Transmission and Distribution (continued):		
Gridwise Membership	$	21
Bi-Directional Valves for HVDC Transmission		25
IEC 61850 Network Management Capability		25
IEC 61850 Testing Project		25
Reducing Transmission Wood Pole Fires		32
Transmission Reliability Performance		34
GTI: Underground Duct Rehabilitation		34
CEA Equipment Maintenance		37
Li-ion Battery		39
Power System Load Modeling Phase 2		41
345kv Optical Instrument Transformers		48
Transmission Line EMI Detection		50
Utility Application BESS		50
CEA Membership & Projects		52
SuperPower HTS Matrix Fault Current Limiter		55
EHV Transformer Condition Monitor		70
PSerc		72
Galloping Conductor Mitigation		78
Fast Fault Detector		79
UCA/IEC 61850 Testing		79
CERTS Phasor Application		109
DR EPRI Annual Research Portfolio		114
Enhanced Distribution Monitoring		148
Distribution EMI Inspection		171
Transmission Program Management		190
High Temp Superconducting Cable		201
Advanced Distribution Program Management		204
Areva Transmission Operations Visualization		216
NEETRAC Membership		296
Distribution EPRI Annual Research Portfolio		336
Transmission EPRI Annual Research Portfolio		391
Transmission EPRI Base Program		423
Advanced Distribution EPRI Base Program		620
10 Items under $5,000		20
SUB-TOTAL		4,506
TOTAL Billable Balance Sheet Amounts		18,187
Less Amount Billed		18,187
Net amount remaining on the Balance Sheet	$	0

SCHEDULE XI - PROPRIETARY CAPITAL
(Dollars in thousands except per share amounts)

ACCOUNT NUMBER	CLASS OF STOCK	NUMBER OF SHARES AUTHORIZED	PAR OR STATED VALUE PER SHARE	OUTSTANDING CLOSE OF PERIOD NO. OF SHARES	OUTSTANDING CLOSE OF PERIOD TOTAL AMOUNT
Account 201 - Common Stock Issued					
	Common Stock Issued	20,000	$ 100	13,500	$ 1,350

Instructions: Classify amounts in each account with brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.

ACCOUNT DESCRIPTION	AMOUNT
Account 211 - Miscellaneous Paid-In Capital	
Interest in Central and South West Services, LP	$ 100
	$ **100**
Account 215 - Appropriated Retained Earnings	$ -

Instructions: Give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentage, amount of dividend, date declared and date paid.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	NET INCOME OR (LOSS)	DIVIDENDS PAID	BALANCE AT CLOSE OF YEAR
Account 216 - Unappropriated Retained Earnings	$ -	$ -	$ -	$ -

ACCOUNT DESCRIPTION	AMOUNT
Account 219 - Accumulated Other Comprehensive Income - Minimum Pension Liability	$ **(16,852)**
Total Proprietary Capital	$ **(15,402)**

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SCHEDULE XII - LONG-TERM DEBT
(In Thousands)

Instructions: Advances from associate companies should be reported separately for advances on notes, and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation column. For Account 224 - Other long-term debt, provide the name of creditor company or organization, terms of the obligation, date of maturity, interest rate, and the amount authorized and outstanding.

NAME OF CREDITOR	TERM OF OBLIGATION CLASS & SERIES OF OBLIGATION	DATE OF MATURITY	INTEREST RATE	AMOUNT AUTHORIZED	BALANCE AT BEGINNING OF YEAR	ADDITIONS	DEDUCTIONS (1)	BALANCE AT CLOSE OF YEAR
Account 223 - Advances From Associate Companies								
American Electric Power Company, Inc., Senior Notes		05/15/2006	3.32	$ 50,000	$ 50,000	$ -	$ -	$ 50,000
SUBTOTALS				50,000	50,000	-	-	50,000
Account 224 - Other Long-Term Debt:								
Connecticut Bank & Trust Company (as Trustee), Series E Mortgage Notes		12/15/2008	9.600	70,000	40,000	-	2,000	38,000
SUBTOTALS				70,000	40,000	-	2,000	38,000
TOTALS				$ 120,000	$ 90,000	$ -	$ 2,000	$ 88,000

(1) Give an explanation of deductions:
Account 224 - Loan Payments. See Note 8, Schedule XIV for further explanation of dates of maturity.

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 233 - Notes Payable to Associate Companies		
American Electric Power Company, Inc.	$ -	$ 9,896
TOTALS	$ -	$ 9,896
Account 234 - Accounts Payable to Associate Companies		
AEP Coal Marketing LLC	$ 362	$ -
AEP Delaware Investment Company II	-	80
AEP EmTech LLC	18	-
AEP Energy Services Investments, Inc.	24	-
AEP Generating Company	17	-
AEP Kentucky Coal, LLC	-	44
AEP Pro Serv, Inc.	30	11
AEP Resources, Inc.	19	-
AEP System Pool	43	50
AEP Texas Central Company	1,372	934
AEP Texas North Company	537	159
AEP Utilities, Inc.	-	1,233
AEPES General and Administrative	130	337
American Electric Power Company, Inc.	2,525	1,519
Appalachian Power Company	10,448	13,430
Cardinal Operating Company	115	51
Columbus Southern Power Company	6,808	10,772
Colomet, Inc.	82	-
Conesville Coal Preparation Company	33	-
CSW Energy, Inc.	46	11
Houston Pipe Line Company LP	604	-
Indiana Michigan Power Company	33,505	35,589
Kentucky Power Company	2,715	3,487
Kingsport Power Company	1,116	891
Memco Consolidated	10	10
Ohio Power Company	44,969	47,101
Public Service Company of Oklahoma	6,429	14,651
Southern Appalachian Coal Company	-	800

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 234 - Accounts Payable to Associate Companies (con't)		
Southwestern Electric Power Company	$ 5,211	$ 7,501
United Sciences Testing, Inc.	37	-
Wheeling Power Company	654	422
Miscellaneous (26 companies)	85	33
TOTALS	$ 117,944	$ 139,116
Account 242 - Miscellaneous Current and Accrued Liabilities		
Accrued Payroll	$ 17,011	$ 16,782
Accrued Audit Fees	11	19
Control Cash Disbursements Account	8,918	8,657
Deferred Compensation Benefits	1,046	1,228
Employee Benefits	2,344	3,149
Incentive Pay	79,288	125,204
Real and Personal Property Taxes	262	233
Rent on John E. Dolan Engineering Laboratory	616	572
Rent on Personal Property	219	225
2005 Reorganization Costs	-	9,121
Vacation Pay	45,885	43,020
Workers' Compensation	1,867	1,403
TOTALS	$ 157,467	$ 209,613

Instructions: The space below is provided for important notes regarding the financial statements or any account thereof. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

American Electric Power Service Corporation (the Company or AEPSC) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP or Parent Company), a public utility holding company. We provide certain managerial and professional services including administrative and engineering services to the affiliated companies in the American Electric Power System (AEP System) and periodically to nonaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

As a subsidiary of AEP, we were subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA 1935) for the periods presented. The Energy Policy Act of 2005 repealed PUHCA 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA 2005). With the repeal of PUHCA 1935, the SEC no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over holding company-related activities has been transferred to the Federal Energy Regulatory Commission (FERC). Regulations and required reporting under PUHCA 2005 are reduced compared to PUHCA 1935. Specifically, the FERC has jurisdiction over issuances of securities, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records.

Basis of Accounting

Our accounting conforms to the Uniform System of Accounts for Mutual and Subsidiary Service Companies prescribed by the SEC pursuant to PUHCA 1935. As a cost-based rate-regulated entity, our financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), the financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions to match expenses and revenues in cost-based rates. Regulatory assets are expected to be recovered in future periods through billings to client companies and regulatory liabilities are expected to reduce future billings. We have reviewed all the evidence currently available and concluded that we continue to meet the requirements to apply SFAS 71.

Among other things, application of SFAS 71 requires that our billing rates be cost-based regulated. In the event a portion of our business were to no longer meet those requirements, net regulatory assets would have to be written off for that portion of the business and long-term assets would have to be tested for possible impairment. If net regulatory assets were written off, the amounts would be recoverable from affiliated companies.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31, 2005	December 31, 2004	Recovery/ Refund Period
	(in thousands)		
Regulatory Assets			
Unamortized Loss on Reacquired Debt	$ 1,266	$ 1,687	Up to 5 Years (a)
SFAS 109 Regulatory Asset	115	426	Various Periods (b)
Total Regulatory Assets	$ 1,381	$ 2,113	
Regulatory Liabilities			
Deferred Amounts Due to Affiliates for Income Tax Benefits	$ 7,809	$ 9,565	Various Periods (b)
Deferred Investment Tax Credits	648	699	Up to 13 Years (b)
Total Regulatory Liabilities	$ 8,457	$ 10,264	

(a) Amount effectively earns a return.
(b) Amount does not earn a return.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires in certain instances the use of management's estimates. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could differ from those estimates.

Revenues and Expenses

We provide certain managerial and professional services to both affiliated and nonaffiliated companies. The costs of the services are billed on a direct-charge basis, whenever possible, and on a reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, all of which is furnished by AEP.

Income Taxes and Investment Tax Credits

We follow the liability method of 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.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of determining regulated rates for services), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method unless they have been deferred in accordance with regulatory treatment. Investment tax credits that have been deferred are being amortized over the life of the related investment.

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Property and Equipment

Property is stated at original cost. Land, structures and structural improvements are generally subject to first mortgage liens. Depreciation is provided on a straight-line basis over the estimated useful lives of the property. The annual composite depreciation rate was 4.77% and 5.02% for the years ended December 31, 2005 and 2004, respectively.

Allowance for funds used during construction (AFUDC) represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of the related capital assets. The amounts of AFUDC capitalized for 2005 and 2004 were $291,000 and $613,000, respectively.

We transferred capitalized software costs of $1 million and $12 million in 2005 and 2004, respectively, to other AEP affiliated companies.

Investments

Investments include the cash surrender value of trust owned life insurance policies held under a grantor trust to provide funds for nonqualified deferred compensation plans we sponsor.

Accounts Receivable

Our Accounts Receivable is primarily from affiliated companies for professional services rendered. These billings for services rendered are issued monthly by us based on a work order system that is maintained in accordance with PUHCA 1935. The affiliated companies generally remit these payments to us within 30 days.

Long-term Debt

With SEC staff approval, gains and losses on reacquired debt are deferred and amortized over the term of the replacement debt.

Debt issuance expenses are amortized over the term of the related debt, with the amortization included in Interest Expenses.

Comprehensive Income (Loss)

Comprehensive Income (Loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive Income (Loss) has two components: Net Income and Other Comprehensive Income (Loss) (OCI). Accumulated OCI is included on the balance sheet in the shareholder's deficit section.

Accumulated Other Comprehensive Income (Loss) related to the Minimum Pension Liability, net of tax, as of December 31, 2005 and 2004 was $17 million and $76 million, respectively.

Guarantees

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2005, the maximum potential loss for this lease agreement was approximately $12.7 million assuming the fair market value of the equipment is zero at the end of the lease term.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued during 2005 that we have determined relates to our operations.

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

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." A cumulative effect of a change in accounting principle will be recorded for the effect of initially applying the statement.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the Financial Accounting Standards Board (FASB) issued SFAS 154, which replaces Accounting Principles Board (APB) Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. SFAS 154 was effective for us beginning January 1, 2006 and will be applied as necessary.

Future Accounting Changes

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

3. COMMITMENTS AND CONTINGENCIES

Construction

Construction commitments have been made to support our operations and are estimated to be $2.1 million for 2006. Estimated construction expenditures are subject to periodic review and modifications may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities which are not completely insured would be recovered from affiliated companies.

Enron Bankruptcy

In 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron,

AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim sought to unwind the effects of the transaction. In December 2005, the parties reached a settlement resulting in no impact on our results of operations, cash flows, or financial condition.

We are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of litigation, any potential liability which may result would be recoverable from affiliated companies.

4. BENEFIT PLANS

We participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, we participate in other postretirement benefit plans sponsored by AEP to provide medical and life insurance benefits for retired employees. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004. The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result of implementing FSP FAS 106-2, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO. Our reduction in the net periodic postretirement cost for 2004 was $6 million.

The following tables provide a reconciliation of the changes in the AEP plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2005, and a statement of the funded status as of December 31 for both years:

Pension Obligations, Plan Assets, Funded Status as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Service Cost	93	86	42	41
Interest Cost	228	228	107	117
Participant Contributions	-	-	20	18
Actuarial (Gain) Loss	191	379	(320)	(130)
Benefit Payments	(273)	(273)	(118)	(109)
Projected Obligation at December 31	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,555	$ 3,180	$ 1,093	$ 950
Actual Return on Plan Assets	224	409	70	98
Company Contributions	637	239	107	136
Participant Contributions	-	-	20	18
Benefit Payments	(273)	(273)	(118)	(109)
Fair Value of Plan Assets at December 31	$ 4,143	$ 3,555	$ 1,172	$ 1,093

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Funded Status:				
Funded Status at December 31	$ (204)	$ (553)	$ (659)	$ (1,007)
Unrecognized Net Transition Obligation	-	-	152	179
Unrecognized Prior Service Cost (Benefit)	(9)	(9)	5	5
Unrecognized Net Actuarial Loss	1,266	1,040	471	795
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

Amounts Recognized in the Balance Sheets as of December 31, 2005 and 2004:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Prepaid Benefit Costs	$ 1,099	$ 524	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(31)	(28)
Additional Minimum Liability	(35)	(566)	N/A	N/A
Intangible Asset	6	36	N/A	N/A
Pretax Accumulated Other Comprehensive Income	29	530	N/A	N/A
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

N/A = Not Applicable

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

	Target Allocation	**Percentage of Plan Assets at Year End**	
Asset Category	**2006**	**2005**	**2004**
	(in percentages)		
Equity Securities	70	66	68
Debt Securities	28	25	25
Cash and Cash Equivalents	2	9	7
Total	100	100	100

The asset allocations for AEP's other postretirement benefit plans at the end of 2005 and 2004, and target allocation for 2006, by asset category, are as follows:

	Target Allocation	**Percentage of Plan Assets at Year End**	
Asset Category	**2006**	**2005**	**2004**
	(in percentages)		
Equity Securities	66	68	70
Debt Securities	31	30	28
Other	3	2	2
Total	100	100	100

AEP's investment strategy for its employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate. Because of the $320 million and $200 million contributions at the end of 2005 and 2004, respectively, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006 and 2005.

The value of AEP's pension plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The qualified plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits).

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

	As of December 31,	
	2005	2004
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,053	$ 3,918
Nonqualified Pension Plans	81	80
Total	$ 4,134	$ 3,998

Minimum Pension Liability

AEP's combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $204 million and $553 million at December 31, 2005 and December 31, 2004, respectively. For AEP's underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2005 and 2004 were as follows:

	Underfunded Pension Plans As of December 31,	
	2005	2004
	(in millions)	
Projected Benefit Obligation	$ 84	$ 2,978
Accumulated Benefit Obligation	81	2,880
Fair Value of Plan Assets	-	2,406
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	81	474

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

AEP made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet its goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in percentages)			
Discount Rate	5.50	5.50	5.65	5.80
Rate of Compensation Increase	5.90(a)	3.70	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The method used to determine the discount rate that AEP utilizes for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moody's AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, AEP changed to a duration-based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2005 and 2004 under this method was 5.50% for pension plans and 5.65% and 5.80%, respectively, for other postretirement benefit plans.

For 2005, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

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

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Required Contributions (a)	$ 8	$ 10	N/A	N/A
Additional Discretionary Contributions	$ -	$ 626 (b)	$ 96	$ 107

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

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

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

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2006	$ 291	$ 117	$ (9)
2007	305	125	(10)
2008	316	133	(10)
2009	335	140	(11)
2010	344	148	(11)
Years 2011 to 2015, in Total	1,811	857	(65)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
			(in millions)			
Service Cost	$ 93	$ 86	$ 80	$ 42	$ 41	$ 42
Interest Cost	228	228	233	107	117	130
Expected Return on Plan Assets	(314)	(292)	(318)	(92)	(81)	(64)
Amortization of Transition (Asset) Obligation	-	2	(8)	27	28	28
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	55	17	11	25	36	52
Net Periodic Benefit Cost (Credit)	61	40	(3)	109	141	188
Capitalized Portion	(17)	(10)	(3)	(33)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 44	$ 30	$ (6)	$ 76	$ 95	$ 145

Net Pension Cost

Our net periodic benefit cost for the pension plans for fiscal years 2005 and 2004 were $31 million and $22 million, respectively. Our net periodic benefit cost for the other postretirement benefit plans for fiscal years 2005 and 2004 were $22 million and $27 million, respectively.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
			(in percentages)			
Discount Rate	5.50	6.25	6.75	5.80	6.25	6.75
Expected Return on Plan Assets	8.75	8.75	9.00	8.37	8.35	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2005 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was 8.75% for 2005. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was increased to 8.37%.

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

Health Care Trend Rates	2005	2004
Initial	9.0%	10.0%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2009	2009

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	263	(215)

Retirement Savings Plan

We participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The contributions to the plan are 75% of the first 6% of eligible employee compensation. Our cost for contributions to the retirement savings plans for fiscal years 2005 and 2004 were $20.0 million and $19.2 million, respectively.

5. FINANCIAL INSTRUMENTS

The carrying amount of cash, other cash deposits, accounts receivable and accounts payable approximates fair value because of the short-term maturities of these instruments. The fair value of long-term debt, excluding advances from AEP, was $92.5 million and $97.8 million at December 31, 2005 and 2004, respectively. The balances are based on quoted market prices for similar issues and the current interest rates offered for debt of the same remaining maturities. The carrying amount for long-term debt was $88.0 million and $90.0 million at December 31, 2005 and 2004, respectively.

We are subject to market risk as a result of changes in interest rates primarily due to short-term and long-term borrowings used to fund our business operations. Our debt portfolio has fixed and variable interest rates with terms from one day to three years at December 31, 2005. A near term change in interest rates should not materially affect results of operations or financial position since we would not expect to liquidate our entire debt portfolio in a one year holding period.

6. INCOME TAXES

The details of income taxes are as follows:

	Year Ended December 31, 2005	2004
	(in thousands)	
Current	$ (14,831)	$ (4,503)
Deferred	4,237	4,494
Deferred Investment Tax Credits	(51)	(51)
Total Income Tax Credit	$ (10,645)	$ (60)

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 rate, and the total amount of income taxes:

	Year Ended December 31, 2005	2004
	(in thousands)	
Net Income	$ -	$ -
Plus: Income Tax Credit	(10,645)	(60)
Pre-Tax Loss	$ (10,645)	$ (60)
Income Tax on Pretax Loss at Statutory Rate (35%)	$ (3,726)	$ (21)
Increase (Decrease) in Income Tax Resulting From the Following Items:		
Trust Owned Life Insurance	(817)	(269)
Corporate Owned Life Insurance	(1,056)	231
State and Local Income Taxes	(57)	(1,626)
Medicare Subsidy	(3,104)	(2,098)
Other	(1,885)	3,723
Total Income Tax Credit	$ (10,645)	$ (60)
Effective Income Tax Rate	N.M.	N.M.

N.M. = Not Meaningful

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

	December 31, 2005	2004
	(in thousands)	
Deferred Tax Assets	$ 104,824	$ 117,256
Deferred Tax Liabilities	(78,036)	(52,878)
Net Deferred Tax Assets	$ 26,788	$ 64,378

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Property Related Temporary Differences	$ (19,640)	$ (16,725)
Deferred and Accrued Compensation	49,068	27,629
Capitalized Software Cost	(7,878)	(5,360)
Deferred Income Taxes on Other Comprehensive Income	9,074	41,175
Accrued Pension Expense	(22,105)	501
Accrued Vacation Pay	9,512	10,594
Postretirement Benefits	6,113	6,996
Deferred State Income Taxes	3,002	4,405
Amounts Due to Affiliates for Future Income Taxes	1,642	1,657
All Other, net	(2,000)	(6,494)
Net Deferred Tax Assets	$ 26,788	$ 64,378

We join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP, 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 IRS and other taxing authorities routinely examine the AEP System's tax returns. Management believes that the AEP System has filed tax returns with positions that may be challenged by these tax authorities. These positions relate to the timing and amount of income, deductions and the computation of the tax liability. The AEP System has settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. The AEP System has received Revenue Agent's Reports from the IRS for the years 1991 through 1999, and has filed protests contesting certain proposed adjustments. AEP System returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2005, the AEP System has total provisions for uncertain tax positions of approximately $136 million. In addition, the AEP System accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations, as the company will bill out all associated adjustments.

After Hurricanes Katrina, Rita and Wilma in late 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. Management believes that the application of these tax acts will not materially affect our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed $1,953,000 of deferred state income tax liabilities that are not expected to reverse during the phase-out. The reversal reduced the regulatory asset associated with the deferred state income tax liabilities.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance polices; all of which will not have a material impact on future results of operations and cash flows.

7. LEASES

Leases of structures, improvements, office furniture and miscellaneous equipment are for periods of up to 30 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

The components of lease rental expense are as follows:

	Year Ended December 31, 2005	2004
	(in thousands)	
Lease Payments on Operating Leases	$ 18,088	$ 20,886
Amortization of Capital Leases	22,828	20,253
Interest on Capital Leases	3,919	2,493
Total Lease Rental Expense	$ 44,835	$ 43,632

Property under capital leases and related obligations recorded on the Balance Sheets is as follows:

	December 31, 2005	2004
	(in thousands)	
Property Under Capital Leases		
Structures and Improvements	$ 11,750	$ 11,750
Office Furniture and Miscellaneous Equipment	106,410	83,889
Total Property Under Capital Leases	118,160	95,639
Accumulated Amortization	39,330	28,404
Net Property Under Capital Leases	$ 78,830	$ 67,235
Obligations Under Capital Leases*		
Noncurrent Liability	$ 52,422	$ 46,849
Liability Due Within One Year	26,408	20,253
Total Obligations Under Capital Leases	$ 78,830	$ 67,102

* Represents the present value of future minimum lease payments.

Future minimum lease payments consisted of the following at December 31, 2005:

	Capital Leases	Operating Leases
	(in thousands)	
2006	$ 30,300	$ 8,129
2007	25,804	6,818
2008	16,565	5,579
2009	8,164	3,955
2010	1,998	9,028
Later Years	9,241	7,291
Total Future Minimum Lease Rentals	92,072	$ 40,800
Less Estimated Interest Element	13,242	
Estimated Present Value of Future Minimum Lease Rentals	$ 78,830	

8. LONG-TERM DEBT

Long-term debt was outstanding as follows:

	Interest Rate	December 31, 2005	December 31, 2004
		(in thousands)	
Mortgage Notes:			
Series E (a)	9.60%	$ 38,000	$ 40,000
Notes Payable to Parent Company:			
Due May 15, 2006	3.32%	50,000	50,000
		88,000	90,000
Less Portion Due Within One Year		52,000	2,000
Total		$ 36,000	$ 88,000

(a) Due in annual installments of $2.0 million until 2007 and the balance in December 2008.

Long-term debt outstanding at December 31, 2005 is payable as follows:

	Principal Amount
	(in thousands)
2006	$ 52,000
2007	2,000
2008	34,000
2009	-
Thereafter	-
Total	$ 88,000

9. SHORT-TERM DEBT BORROWINGS

The AEP System uses its corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which was established to fund AEP's utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. We participate in the Utility Money Pool. The operation of the Utility Money Pool is designed to match on a daily basis the available cash and borrowing requirements of the participants. Participants with excess cash loan funds to the Utility Money Pool, reducing the amount of external funds AEP needs to borrow to meet the short-term cash requirements of other participants with advances from the Utility Money Pool. AEP borrows the funds as needed to meet the net cash requirements of the Utility Money Pool participants.

For our advances to and borrowings from the Utility Money Pool, we include interest income and interest expense in Interest Income and Interest Expense on our Statement of Operations. We received interest income of $1.3 million and $0.4 million for loans made to the money pool in 2005 and 2004, respectively. We incurred interest expense of $0.2 million and $0.4 million for amounts borrowed from the Utility Money Pool in 2005 and 2004, respectively.

At December 31, 2005, our net outstanding borrowings from the Utility Money Pool were $9.9 million. At December 31, 2004, our net outstanding loan to the Utility Money Pool was $29.2 million. We report our position as the lender and borrower of funds with the Utility Money Pool as Advances to Affiliates and Advances from Affiliates on our Balance Sheets, respectively.

Additional information for the year ended December 31, 2005 for our borrowings from and loans to the Utility Money Pool is summarized in the following table:

	2005	2004
	(in millions)	
Maximum Borrowings from Utility Money Pool	$ 79	$ 123
Maximum Loans to Utility Money Pool	174	117
Average Borrowings from Utility Money Pool	29	46
Average Loans to Utility Money Pool	51	57
	(in percentages)	
Maximum Interest Rate for Funds Borrowed from Utility Money Pool	4.49	1.92
Minimum Interest Rate for Funds Borrowed from Utility Money Pool	2.52	0.89
Maximum Interest Rate for Funds Loaned to Utility Money Pool	4.47	2.24
Minimum Interest Rate for Funds Loaned to Utility Money Pool	1.63	0.94
Average Interest Rate for Funds Borrowed from Utility Money Pool	3.35	1.36
Average Interest Rate for Funds Loaned to Utility Money Pool	3.17	1.84

10. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As result of AEP's staffing and budget review, approximately 500 positions throughout AEP were identified for elimination. Accordingly, approximately $21 million pretax severance benefits expense was recorded (primarily in Maintenance and Other Operation) in 2005. The following table shows the total expense recorded and the remaining accrual (reflected in Other Current Liabilities) as of December 31, 2005:

	Amount (in millions)
Total Expense	$ 21
Less: Total Payments	12
Remaining Accrual at December 31, 2005	$ 9

11. ASSET IMPAIRMENTS

In June 2004, we entered into negotiations to sell the Dallas office building. A pretax impairment of $2.5 million was recorded in Asset Impairments during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, AEP completed the sale of the Dallas office building for $7.5 million, before closing adjustments, and we recorded an additional impairment of $2.0 million.

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SCHEDULE XV - COMPARATIVE INCOME STATEMENT
(In Thousands)

ACCOUNT	DESCRIPTION	CURRENT YEAR	PRIOR YEAR
	INCOME		
454	Rents from electric properties - NAC	$ 207	$ 177
456	Other electric revenues	6	-
457	Services rendered to associate companies	1,132,802	1,112,655
458	Services rendered to non associate companies	7,423	4,033
419	Interest income - other	1,372	432
421	Miscellaneous income or loss	1,294	1,821
	TOTAL INCOME	1,143,104	1,119,118
	EXPENSES		
500-559	Power production	191,598	185,398
560-579	Transmission	39,546	36,696
580-599	Distribution	60,671	60,789
780-860	Trading	75	467
901-903	Customer accounts expense	135,699	129,468
904	Uncollectible - miscellaneous receivables	(272)	262
905	Miscellaneous customer accounts	416	534
906-917	Customer service & information	6,472	9,433
920	Salaries and wages	322,644	303,956
921	Office supplies and expenses	36,725	40,346
922	Administrative expense transferred - credit	(343,142)	(318,177)
923	Outside services employed	29,969	46,161
924	Property insurance	202	203
925	Injuries and damages	5,384	4,754
926	Employee pensions and benefits	127,204	117,292
928	Regulatory commission expense	5,746	1,024
930.1	General advertising expenses	2,360	2,840
930.2	Miscellaneous general expenses	7,561	7,060
931	Rents	60,819	69,434
935	Maintenance of structures and equipment	50,115	51,402
402	Maintenance expense	-	-
403-405	Depreciation and amortization expense	8,195	8,943
408	Taxes other than income taxes	50,624	40,891
409	Income taxes	(14,831)	(4,503)
410	Provision for deferred income taxes	53,623	51,550
411	Provision for deferred income taxes - credit	(49,437)	(47,107)
411.7	Loss from disposition of plant	3,790	4,532
416	Expense - sports lighting	346	942
417	Administrative - business venture	49	111
418	Non-Operating rental income	286	100
426.1	Donations	4,327	8,615
426.3 - 426.5	Other deductions	4,962	6,118
427	Interest on long-term debt	5,492	5,299
428	Amortization of debt discount and expense	427	427
430	Interest on debt to associate companies	193	389
431	Other interest expense	903	1,310
432	Borrowed funds - construction - credit	(291)	(613)
	TOTAL EXPENSE - INCOME STATEMENT	808,450	826,346
	COST OF SERVICE - BALANCE SHEET		
107	Construction work in progress	259,297	200,225
108	Retirement work in progress	7,322	5,619
120	Nuclear fuel	-	-
121	Nonutility property	-	1
122	Depreciation and amortization of nonutility property	94	73
124	Investments	77	79
151	Fuel stock	1,939	3,225
152	Fuel stock expense undistributed	16,449	15,587
163	Stores expense undistributed	17,293	18,142
182	Regulatory assets	1,000	1,804
183	Preliminary survey and investigation charges	5,050	-
184	Clearing accounts	2	16
186	Miscellaneous deferred debits	6,555	28,016
188	Research, development, or demonstration expenses	18,187	18,342
228	Accumulated miscellaneous operating provisions	-	2
242	Miscellaneous current and accrued Liabilities	1,389	1,641
	TOTAL COST OF SERVICE - BALANCE SHEET	334,654	292,772
	NET INCOME OR (LOSS)	$ -	$ -

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ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457.1	INDIRECT COSTS CHARGED 457.2	COMPENSATION FOR USE OF CAPITAL 457.3	TOTAL AMOUNT BILLED
AEP Acquisition L.L.C.	$ 16	$ 2	$ -	$ 18
AEP C&I Company LLC	37	13	-	50
AEP Coal Co.	87	18	-	105
AEP Coal Marketing LLC	279	52	-	331
AEP Communications, Inc.	33	10	-	43
AEP Communications, LLC	489	85	1	575
AEP Credit, Inc.	407	130	-	537
AEP Delaware Investment Company	21	4	-	25
AEP Desert Sky GP, LLC	3	1	-	4
AEP Desert Sky LP II, LLC	1	-	-	1
AEP Desert Sky LP, LLC	507	87	-	594
AEP Elmwood LLC	324	8	-	332
AEP EmTech LLC	1,209	312	1	1,522
AEP Energy Services Gas Holding Company	482	325	-	807
AEP Energy Services Investments, Inc.	1	-	-	1
AEP Energy Services Limited	288	40	-	328
AEP Gas Marketing LP	76	80	-	156
AEP Gas Power GP, LLC	23	7	-	30
AEP Generating Company	1,604	248	1	1,853
AEP Holdings II CV	28	3	-	31
AEP Kentucky Coal, LLC	1,052	386	-	1,438
AEP Investments, Inc.	254	61	-	315
AEP MEMCo LLC	1,424	102	-	1,526
AEP Nonutility Funding LLC	270	38	-	308
AEP Power Marketing, Inc.	1	-	-	1
AEP Pro Serv, Inc.	2,803	560	2	3,365
AEP Resources, Inc.	2,436	512	1	2,949
AEP System Pool	44,750	17,688	-	62,438
AEP T & D Services , LLC	385	137	-	522
AEP Texas Central Company	89,383	18,614	36	108,033
AEP Texas Commercial & Industrial Retail GP, LLC	7	2	-	9
AEP Texas Commercial & Industrial Retail Limited Parnership	281	110	-	391
AEP Texas North Company	31,555	5,858	12	37,425
AEP Texas POLR, LLC	22	5	-	27
AEP Transportation LLC	1	-	-	1
AEP Utilities, Inc.	248	58	-	306
AEP Utility Funding LLC	119	31	-	150
AEP Wind Energy, LLC	67	30	-	97
AEP Wind Holding, LLC	852	251	1	1,104
AEP Wind LP II, LLC	2	1	-	3
AEPES Coal Trading	4	-	-	4
AEPES General and Administrative	6,158	1,163	7	7,328
AEPR Ohio, LLC	31	3	-	34
AEPSC Revenue Adjustment	1,342	-	-	1,342
American Electric Power Company, Inc.	7,930	1,634	3	9,567
Appalachian Power Company	184,938	34,767	64	219,769
Blackhawk Coal Company	7	2	-	9
C3 Communications, Inc.	8	4	-	12
Cardinal Operating Company	14,379	2,367	5	16,751
Cedar Coal Co.	2	1	-	3
Central Appalachian Coal Company	2	1	-	3
Central Coal Company	2	1	-	3

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ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457 .1	INDIRECT COSTS CHARGED 457 .2	COMPENSATION FOR USE OF CAPITAL 457 .3	TOTAL AMOUNT BILLED
Colomet, Inc.	$ 23	$ 5	$ -	$ 28
Columbus Southern Power Company	86,395	17,448	30	103,873
Conesville Coal Preparation Company	261	36	-	297
CSW Energy Services, Inc.	94	26	-	120
CSW Energy, Inc.	2,522	565	2	3,089
CSW International, Inc.	32	12	-	44
CSW Services International Inc.	6	-	-	6
CSW Sweeny LP II, Inc.	1	1	-	2
Desert Sky Wind Farm LP	172	30	-	202
Diversified Energy Contractors Company, LLC	58	5	-	63
Dolet Hills Lignite Company, LLC	1,399	396	-	1,795
Franklin Real Estate Company	5	2	-	7
Houston Pipe Line Company LP	433	180	-	613
HPL Gas Marketing LP	9	22	-	31
HPL Storage, Inc.	1	1	-	2
Indiana Michigan Power Company	109,242	23,188	38	132,468
Kentucky Power Company	28,955	5,993	11	34,959
Kingsport Power Company	3,123	815	1	3,939
Memco Consolidated	8	1	-	9
Mutual Energy L.L.C.	4	3	-	7
Mutual Energy SWEPCO L. P.	204	58	-	262
Noah I Power GP, Inc.	2	1	-	3
Noah I Power Partners, LP	1	-	-	1
Nuvest, L.L.C.	49	5	-	54
Ohio Power Company	153,711	28,867	53	182,631
POLR Power, L. P.	11	3	-	14
Public Service Company of Oklahoma	69,419	13,537	23	82,979
Rep General Company Partner L.L.C.	59	18	-	77
Rep Holdco Inc.	149	48	-	197
Simco, Inc.	1	-	-	1
Snowcap Coal Company, Inc.	16	-	-	16
Southern Appalachian Coal Company	2	1	-	3
Southwestern Electric Power Company	79,822	15,674	26	95,522
Sweeny Cogeneration LP	9	2	-	11
Trent Wind Farm LP	155	26	-	181
United Sciences Testing, Inc.	2,285	232	1	2,518
Ventures Lease Co., LLC	81	21	-	102
Wheeling Power Company	3,314	785	1	4,100
TOTALS	$ 938,663	$ 193,819	$ 320	$ 1,132,802

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ANALYSIS OF BILLING - NONASSOCIATE COMPANIES - ACCOUNT 458
(In Thousands)

NAME OF NONASSOCIATE COMPANY	DIRECT COST CHARGED 458.1	INDIRECT COST CHARGED 458.2	COMPENSATION FOR USE OF CAPITAL 458.3	TOTAL AMOUNT BILLED
Cinergy	$ 49	$ 2	$ -	$ 51
Cincinnati Gas & Electric	6	1	-	7
Dayton Power & Light	133	5	-	138
Indiana Kentucky Electric Corporation	2,032	339	-	2,371
Ohio Valley Electric Company	4,252	587	-	4,839
Coleto Creek Power LP	15	2	-	17
TOTALS	$ 6,487	$ 936	$ -	$ 7,423

Instruction: Provide a brief description of the services rendered to each nonassociate company:
Engineering, Computer and Environmental Laboratory services.

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SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES

(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - INCOME STATEMENT										
454	Rents from electric properties - NAC	$ (207)	$ -	$ (207)	$ -	$ -	$ -	$ (207)	$ -	$ (207)
456	Other electric revenues	(6)	-	(6)	-	-	-	(6)	-	(6)
419	Interest income - other	(1,372)	-	(1,372)	-	-	-	(1,372)	-	(1,372)
421	Miscellaneous income or loss	(1,292)	(2)	(1,294)	-	-	-	(1,292)	(2)	(1,294)
500-559	Power production	146,598	43,591	190,189	1,250	159	1,409	147,848	43,750	191,598
560-579	Transmission	33,592	5,878	39,470	65	11	76	33,657	5,889	39,546
580-599	Distribution	43,826	16,845	60,671	-	-	-	43,826	16,845	60,671
750-867	Trading	75	-	75	-	-	-	75	-	75
901-903	Customer accounts expense	95,842	39,857	135,699	-	-	-	95,842	39,857	135,699
904	Uncollectible - Misc. Receivable	(272)	-	(272)	-	-	-	(272)	-	(272)
905	Customer assistance	267	149	416	-	-	-	267	149	416
906-917	Customer service & information	4,995	1,477	6,472	-	-	-	4,995	1,477	6,472
920	Salaries and wages	282,210	37,291	319,501	2,735	408	3,143	284,945	37,699	322,644
921	Office supplies and expenses	36,323	290	36,613	110	2	112	36,433	292	36,725
922	Administrative expense transferred - credit	(343,170)	7	(343,163)	20	1	21	(343,150)	8	(343,142)
923	Outside service employed	24,354	3,952	28,306	1,626	37	1,663	25,980	3,989	29,969
924	Property insurance	202	-	202	-	-	-	202	-	202
925	Injuries and damages	5,311	73	5,384	-	-	-	5,311	73	5,384
926	Employee pensions and benefits	127,072	132	127,204	-	-	-	127,072	132	127,204
928	Regulatory commission expense	5,314	432	5,746	-	-	-	5,314	432	5,746
930.1	General advertising expense	2,289	71	2,360	-	-	-	2,289	71	2,360
930.2	Miscellaneous general expense	6,505	1,056	7,561	-	-	-	6,505	1,056	7,561
931	Rents	60,816	3	60,819	-	-	-	60,816	3	60,819
935	Maintenance of structures and equipment	50,079	36	50,115	-	-	-	50,079	36	50,115
403-405	Depreciation and amortization expense	8,195	-	8,195	-	-	-	8,195	-	8,195
408	Taxes other than income taxes	50,624	-	50,624	-	-	-	50,624	-	50,624
409	Income taxes	(14,831)	-	(14,831)	-	-	-	(14,831)	-	(14,831)
410	Provision for deferred income taxes	53,623	-	53,623	-	-	-	53,623	-	53,623
411	Provision for deferred income taxes - credit	(49,437)	-	(49,437)	-	-	-	(49,437)	-	(49,437)
411.7	Loss from Disposition of Plant	3,790	-	3,790	-	-	-	3,790	-	3,790
416	Sports lighting	288	58	346	-	-	-	288	58	346
417	Administrative - business venture	40	9	49	-	-	-	40	9	49
418	Non-Operating rental income	286	-	286	-	-	-	286	-	286
426.1	Donations	4,192	135	4,327	-	-	-	4,192	135	4,327
426.3-426.5	Other deductions	4,661	301	4,962	-	-	-	4,661	301	4,962
427	Interest on long-term debt	5,492	-	5,492	-	-	-	5,492	-	5,492
428	Amortization of debt discount and expense	427	-	427	-	-	-	427	-	427
430	Interest on debt to associate companies	193	-	193	-	-	-	193	-	193
431	Other interest expense	903	-	903	-	-	-	903	-	903
432	Borrowed funds - construction - credit	(291)	-	(291)	-	-	-	(291)	-	(291)
TOTAL COST OF SERVICE - INCOME STATEMENT		647,506	151,641	799,147	5,806	618	6,424	653,312	152,259	805,571

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SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES

(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - BALANCE SHEET										
107	Construction work in progress	$ 227,162	$ 31,790	$ 258,952	$ 222	$ 123	$ 345	$ 227,384	$ 31,913	$ 259,297
108	Retirement work in progress	6,252	1,070	7,322	-	-	-	6,252	1,070	7,322
122	Depreciation & amortization of non-utility property	92	2	94	-	-	-	92	2	94
124	Investments	72	5	77	-	-	-	72	5	77
151	Fuel stock	1,535	404	1,939	-	-	-	1,535	404	1,939
152	Fuel stock expense undistributed	11,490	4,306	15,796	458	195	653	11,948	4,501	16,449
163	Stores expense undistributed	16,803	490	17,293	-	-	-	16,803	490	17,293
182	Regulatory assets	976	24	1,000	-	-	-	976	24	1,000
183	Preliminary survey and investigation	4,548	502	5,050	-	-	-	4,548	502	5,050
184	Clearing accounts	(3)	4	1	1	-	1	(2)	4	2
186	Miscellaneous deferred debits	5,394	1,161	6,555	-	-	-	5,394	1,161	6,555
188	Research, development, or demonstration expense	16,148	2,039	18,187	-	-	-	16,148	2,039	18,187
242	Miscellaneous current and accrued liabilities	1,008	381	1,389	-	-	-	1,008	381	1,389
TOTAL COST OF SERVICE - BALANCE SHEET		291,477	42,178	333,655	681	318	999	292,158	42,496	334,654
TOTAL COST OF SERVICE		$ 938,983	$ 193,819	$ 1,132,802	$ 6,487	$ 936	$ 7,423	$ 945,470	$ 194,755	$ 1,140,225

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

				DEPARTMENT OR SERVICE FUNCTION						
ACCOUNT	DESCRIPTION OF ITEMS	TOTAL AMOUNT	OVERHEAD	AEP UTILITIES EAST	AEP UTILITIES WEST	AEP UTILITY OPERATIONS	AUDIT SERVICES	BUSINESS LOGISTICS	COMMERCIAL OPERATIONS	CORP. ACCTG., PLAN. & STRAT
454	Rents from electric properties - NAC	$ (207)	$ -	$ -	$ -	$ -	$ -	$ (207)	$ -	$ -
456	Other electric revenues	(6)	-	-	-	-	-	-	-	-
419	Interest income - other	(1,372)	-	-	-	-	-	-	-	-
421	Miscellaneous income or loss	(1,294)	(1)	(1)	-	(4)	-	(1,172)	(1)	1
500-559	Power production	191,598	43,749	6	45	2	109	282	42,194	(760)
560-579	Transmission	39,546	6,141	31	1	219	-	36	38	(7)
580-599	Distribution	60,671	16,593	8,087	6,873	(226)	-	76	-	-
780-860	Trading	75	-	-	-	-	-	-	-	-
901-903	Customer accounts expense	135,699	39,857	1,403	1,901	20	-	2	-	(733)
904	Uncollectible - Misc. Receivable	(272)	-	-	-	-	-	5	-	-
905	Miscellaneous customer accounts	416	148	-	9	-	-	-	-	-
906-917	Customer service & information	6,472	1,477	1,244	1,636	8	-	1	-	-
920	Salaries and wages	322,644	37,700	6,488	6,222	7,841	8,271	13,327	3,881	(6,815)
921	Office supplies and expenses	36,725	292	634	806	(212)	338	7,048	186	11
922	Administrative expense transferred - credit	(343,142)	7	21,325	16,952	2,644	975	(59,196)	20,349	2,994
923	Outside services employed	29,969	3,989	130	(311)	33	363	3,473	(56)	(276)
924	Property insurance	202	-	-	-	-	-	-	-	-
925	Injuries and damages	5,384	73	208	1	-	-	-	-	-
926	Employee pensions and benefits	127,204	132	194	177	88	109	291	460	29
928	Regulatory commission expense	5,746	432	27	2,009	-	-	-	195	(89)
930.1	General advertising expenses	2,360	71	765	459	-	-	-	-	-
930.2	Miscellaneous general expenses	7,561	1,057	66	83	28	30	5	45	38
931	Rents	60,819	3	6	12	7	1	27,472	6	(1)
935	Maintenance of structures and equipment	50,115	36	5	8	5	72	7,586	1	-
402	Maintenance Expense	-	-	-	-	-	-	-	-	-
403-405	Depreciation and amortization expense	8,195	-	-	-	-	-	8,195	-	-
408	Taxes other than income taxes	50,624	-	1,073	1,219	164	473	4,357	2,176	65
409	Income taxes	(14,831)	-	-	-	-	-	-	-	-
410	Provision for deferred income taxes	53,623	-	-	-	-	-	-	-	-
411	Provision for deferred income taxes - credit	(49,437)	-	-	-	-	-	-	-	-
411.7	Loss from disposition of plant	3,790	-	-	-	-	-	3,790	-	-
416	Expense - sports lighting	346	59	-	-	-	-	-	-	(5)
417	Administrative - business venture	49	9	-	9	-	-	-	-	-
418	Non-Operating rental income	286	-	-	-	-	-	286	-	-
426.1	Donations	4,327	135	64	7	-	8	-	14	-
426.3 - 426.5	Other deductions	4,962	301	349	805	10	-	-	2	16
427	Interest on long-term debt	5,492	-	-	-	-	-	-	-	-
428	Amortization of debt discount and expense	427	-	-	-	-	-	-	-	-
430	Interest on debt to associate companies	193	-	-	-	-	-	-	-	-
431	Other interest expense	903	-	-	-	-	-	-	-	-
432	Borrowed funds - construction - credit	(291)	-	-	-	-	-	(291)	-	-
107	Construction work in progress	259,297	31,912	2,477	2,252	25	338	2,596	4,257	(2,465)
108	Retirement work in progress	7,322	1,070	204	385	-	-	109	-	-
122	Depreciation and amortization of nonutility property	94	2	-	-	-	-	92	-	-
124	Investments	77	5	-	-	-	-	50	-	-
151	Fuel stock	1,939	404	-	-	-	-	-	-	-
152	Fuel stock expense undistributed	16,449	4,501	-	-	-	2	11	1,327	(524)
163	Stores expense undistributed	17,293	490	-	-	(24)	-	16,146	-	(96)
182	Regulatory Assets	1,000	24	-	33	-	-	-	3	-
183	Preliminary survey and investigation charges	5,050	502	-	-	-	-	41	13	-
184	Clearing accounts	2	4	-	-	-	-	-	-	-
186	Miscellaneous deferred debits	6,555	1,161	149	132	(455)	18	11	178	140
188	Research, development, or demonstration expenses	18,187	2,039	-	-	(4)	-	-	-	-
242	Miscellaneous current and accrued liabilities	1,389	381	-	-	-	-	2	-	(20)
	TOTAL COST OF SERVICE	$ 1,140,225	$ 194,755	$ 44,934	$ 41,725	$ 10,169	$ 11,107	$ 34,424	$ 75,268	$ (8,497)

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION									
ACCOUNT	DESCRIPTION OF ITEMS	CORPORATE ACCOUNTING	CORPORATE COMMUN.	CORPORATE FINANCE	CORPORATE PLAN. & BUDG.	CUSTOMER OPERATIONS	DISTRIBUTION SERVICES	EXECUTIVE GROUP	FUEL, EMISSIONS & LOGISTICS	GBS SVP BUS. SERVICES	GENERATION
454	Rents from electric properties - NAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other electric revenues	-	-	-	-	-	-	(6)	-	-	-
419	Interest income - other	-	-	(1,372)	-	-	-	-	-	-	-
421	Miscellaneous income or loss	(31)	-	-	-	(74)	-	-	-	-	(4)
500-559	Power production	3,057	3	7	1,732	152	82	1,261	2,425	4,421	55,394
560-579	Transmission	27	-	-	-	241	338	24	-	-	1,034
580-599	Distribution	10	-	-	-	6,784	15,549	38	-	-	(4,069)
780-860	Trading	-	-	-	-	-	-	-	-	-	-
901-903	Customer accounts expense	3,776	-	-	-	89,117	453	-	-	-	(122)
904	Uncollectible - Misc. Receivable	-	-	-	-	(278)	-	-	-	-	-
905	Miscellaneous customer accounts	-	-	-	-	254	-	-	-	-	(1)
906-917	Customer service & information	-	87	-	-	1,844	18	12	-	-	2
920	Salaries and wages	39,957	7,060	5,659	10,095	2,267	683	25,439	1,076	2,664	9,279
921	Office supplies and expenses	1,036	648	2,695	202	273	(15)	4,799	61	451	1,177
922	Administrative expense transferred - credit	16,590	1,990	1,792	3,632	47,386	21,995	23,850	8,954	3,938	14,596
923	Outside services employed	2,460	1,177	46	274	49	(77)	727	(124)	492	1,380
924	Property insurance	-	-	-	-	-	-	-	-	-	-
925	Injuries and damages	-	-	-	-	58	13	-	-	-	(11)
926	Employee pensions and benefits	434	1,253	89	150	692	151	526	156	86	707
928	Regulatory commission expense	383	-	78	(1)	-	-	1	11	88	-
930.1	General advertising expenses	-	1,013	-	-	4	-	-	-	-	-
930.2	Miscellaneous general expenses	136	333	47	111	147	2,711	1,847	5	5	(56)
931	Rents	72	57	1	3	21	19	5	13	14	127
935	Maintenance of structures and equipment	2	-	9	1	59	1	-	2	3	13
402	Maintenance Expense	-	-	-	-	-	-	-	-	-	-
403-405	Depreciation and amortization expense	-	-	-	-	-	-	-	-	-	-
408	Taxes other than income taxes	4,055	445	339	701	4,926	1,104	741	755	599	7,258
409	Income taxes	(14,831)	-	-	-	-	-	-	-	-	-
410	Provision for deferred income taxes	53,623	-	-	-	-	-	-	-	-	-
411	Provision for deferred income taxes - credit	(49,437)	-	-	-	-	-	-	-	-	-
411.7	Loss from disposition of plant	-	-	-	-	-	-	-	-	-	-
416	Expense - sports lighting	19	-	-	-	273	-	-	-	-	-
417	Administrative - business venture	1	-	-	-	-	5	-	-	-	1
418	Non-Operating rental income	-	-	-	-	-	-	-	-	-	-
426.1	Donations	-	3	-	-	1	-	3,528	-	6	1
426.3 - 426.5	Other deductions	12	397	-	2	21	4	2,955	-	-	9
427	Interest on long-term debt	-	-	5,492	-	-	-	-	-	-	-
428	Amortization of debt discount and expense	-	-	427	-	-	-	-	-	-	-
430	Interest on debt to associate companies	-	-	193	-	-	-	-	-	-	-
431	Other interest expense	471	-	385	-	-	-	-	-	-	-
432	Borrowed funds - construction - credit	-	-	-	-	-	-	-	-	-	-
107	Construction work in progress	3,903	33	100	573	3,908	6,098	3,883	204	6,046	61,229
108	Retirement work in progress	-	-	-	-	3	61	3	-	39	4,716
122	Depreciation and amortization of nonutility property	-	-	-	-	-	-	-	-	-	-
124	Investments	-	-	-	-	-	-	-	-	-	-
151	Fuel stock	-	-	-	-	-	-	-	1,664	-	62
152	Fuel stock expense undistributed	2,005	-	-	15	-	-	83	7,327	385	437
163	Stores expense undistributed	376	-	-	-	-	-	2	-	-	2
182	Regulatory Assets	11	145	-	-	2	-	-	-	-	2
183	Preliminary survey and investigation charges	1	-	-	-	-	-	26	-	255	917
184	Clearing accounts	-	-	-	-	-	-	(4)	-	-	1
186	Miscellaneous deferred debits	81	95	40	183	149	153	97	-	18	168
188	Research, development, or demonstration expenses	-	-	-	4	1	5,612	5	-	37	5
242	Miscellaneous current and accrued liabilities	72	-	-	-	-	-	-	954	-	-
	TOTAL COST OF SERVICE	$ 68,271	$ 14,739	$ 16,027	$ 17,677	$ 158,280	$ 54,958	$ 69,842	$ 23,483	$ 19,547	$ 154,254

SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION									
ACCOUNT	DESCRIPTION OF ITEMS	GEN. - FOSSIL & HYDRO	GET SVP ENG. TECH ENV SERV.	HUMAN RESOURCES	INFORMATION TECHNOLOGY	INVESTOR RELATIONS	LEGAL	NUCLEAR GENERATION	REGULATORY SERVICES	RISK MANAGEMENT	TRANSMISSION
454	Rents from electric properties - NAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other electric revenues	-	-	-	-	-	-	-	-	-	-
419	Interest income - other	-	-	-	-	-	-	-	-	-	-
421	Miscellaneous income or loss	(1)	-	(1)	(3)	-	-	-	-	-	(2)
500-559	Power production	27,776	2,956	91	1,035	-	733	866	775	2,094	1,111
560-579	Transmission	1	-	-	2,081	-	-	-	925	-	28,416
580-599	Distribution	-	300	24	7,263	-	-	-	392	1	2,976
780-860	Trading	-	-	-	75	-	-	-	-	-	-
901-903	Customer accounts expense	-	-	-	14	-	-	-	4	-	7
904	Uncollectible - Misc. Receivable	-	-	-	1	-	-	-	-	-	-
905	Miscellaneous customer accounts	3	3	-	-	-	-	-	-	-	-
906-917	Customer service & information	1	-	-	142	-	-	-	-	-	-
920	Salaries and wages	873	1,247	24,416	80,201	989	20,035	-	7,465	5,677	647
921	Office supplies and expenses	677	115	2,725	9,974	162	1,280	-	280	817	265
922	Administrative expense transferred - credit	22,764	4,718	(208,433)	(355,484)	98	2,992	10,444	1,111	3,248	24,627
923	Outside services employed	(442)	168	2,351	11,427	305	2,129	(139)	189	363	(131)
924	Property insurance	-	-	-	-	-	-	-	-	202	-
925	Injuries and damages	-	-	626	-	-	119	-	-	4,296	1
926	Employee pensions and benefits	235	76	119,045	946	8	297	10	92	99	672
928	Regulatory commission expense	11	-	-	-	-	2,453	-	148	-	-
930.1	General advertising expenses	-	-	47	1	-	-	-	-	-	-
930.2	Miscellaneous general expenses	-	1	3	310	-	64	-	-	69	476
931	Rents	6	21	16	32,896	-	8	-	-	2	32
935	Maintenance of structures and equipment	11	-	5	42,273	-	1	1	-	1	20
402	Maintenance Expense	-	-	-	-	-	-	-	-	-	-
403-405	Depreciation and amortization expense	-	-	-	-	-	-	-	-	-	-
408	Taxes other than income taxes	1,910	416	2,465	7,807	51	1,083	24	558	546	5,314
409	Income taxes	-	-	-	-	-	-	-	-	-	-
410	Provision for deferred income taxes	-	-	-	-	-	-	-	-	-	-
411	Provision for deferred income taxes - credit	-	-	-	-	-	-	-	-	-	-
411.7	Loss from disposition of plant	-	-	-	-	-	-	-	-	-	-
416	Expense - sports lighting	-	-	-	-	-	-	-	-	-	-
417	Administrative - business venture	-	-	-	4	-	-	-	1	-	19
418	Non-Operating rental income	-	-	-	-	-	-	-	-	-	-
426.1	Donations	-	196	363	-	-	-	-	1	-	-
426.3 - 426.5	Other deductions	-	(43)	4	11	-	64	-	41	1	1
427	Interest on long-term debt	-	-	-	-	-	-	-	-	-	-
428	Amortization of debt discount and expense	-	-	-	-	-	-	-	-	-	-
430	Interest on debt to associate companies	-	-	-	-	-	-	-	-	-	-
431	Other interest expense	-	-	-	-	-	-	-	-	47	-
432	Borrowed funds - construction - credit	-	-	-	-	-	-	-	-	-	-
107	Construction work in progress	6,006	5,589	310	54,121	-	443	-	27	253	65,179
108	Retirement work in progress	274	-	3	3	-	-	-	-	-	452
122	Depreciation and amortization of nonutility property	-	-	-	-	-	-	-	-	-	-
124	Investments	-	-	-	-	-	22	-	-	-	-
151	Fuel stock	(191)	-	-	-	-	-	-	-	-	-
152	Fuel stock expense undistributed	117	3	-	18	-	473	-	-	248	21
163	Stores expense undistributed	94	-	9	294	-	-	-	-	-	-
182	Regulatory Assets	-	-	-	2	-	414	-	362	-	2
183	Preliminary survey and investigation charges	16	3,062	-	-	-	195	-	-	1	21
184	Clearing accounts	1	-	-	-	-	-	-	-	-	-
186	Miscellaneous deferred debits	609	-	2	454	-	1,415	-	19	22	1,716
188	Research, development, or demonstration expenses	18	8,617	-	-	-	31	-	-	-	1,822
242	Miscellaneous current and accrued liabilities	-	-	-	-	-	-	-	-	-	-
	TOTAL COST OF SERVICE	$ 60,769	$ 27,445	$ (55,929)	$ (104,134)	$ 1,613	$ 34,251	$ 11,206	$ 12,390	$ 17,987	$ 133,664

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

DEPARTMENTAL ANALYSIS OF SALARIES
(In Thousands except Number of Personnel)

NAME OF DEPARTMENT *Indicate each department or service function.*	DEPARTMENTAL SALARY EXPENSE TOTAL AMOUNT	INCLUDED IN AMOUNTS BILLED TO PARENT COMPANY	OTHER ASSOCIATES	NON ASSOCIATES	NUMBER OF PERSONNEL END OF YEAR
AEP Utilities - East	$ 9,128	$ 52	$ 9,076	$ -	75
AEP Utilities - West	9,907	107	9,800	-	16
AEP Utility Operations	451	-	448	3	2
Audit Services	3,672	46	3,625	1	45
Business Logistics	10,625	25	10,585	15	319
Commercial Operations	24,102	5	24,088	9	277
Corp Accounting, Planning/Strategy	348	98	250	-	1
Corporate Accounting	21,849	308	21,541	-	323
Corporate Communications	3,280	138	3,142	-	35
Corporate Finance	2,753	57	2,639	57	30
Corporate Planning & Budgeting	7,368	81	7,286	-	71
Customer Operations	42,927	21	42,906	-	1,012
Distribution Services	5,246	2	5,244	-	123
Executive Group	4,064	450	3,376	238	29
Fuel, Emissions & Logistics	6,797	-	6,563	234	81
GBS SVP Business Services	6,381	2	6,332	47	84
Generation	81,201	31	79,463	1,707	1,026
Generation-Fossil & Hydro	19,001	1	18,983	17	213
GET SVP Engineering, Technical & Environmental Sei	3,535	-	3,519	16	42
Human Resources	(216)	(1)	(215)	-	231
Information Technology	12,513	34	12,479	-	881
Investor Relations	556	11	545	-	6
Legal	9,051	345	8,686	20	82
Nuclear Generation	416	-	416	-	1
Regulatory Services	4,595	21	4,572	2	66
Risk Management	6,397	25	6,345	27	60
Transmission	51,155	3	51,096	56	607
Totals	$ 347,101	$ 1,862	$ 342,790	$ 2,449	5,738

These amounts represent salary dollars that were billed as salaries, and exclude salary dollars that are a component of an overhead pool. These amounts are charged to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

MISCELLANEOUS GENERAL EXPENSES - ACCOUNT 930.2
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

DESCRIPTION	AMOUNT
Salaries, Salary Related Expenses and Overheads	$ 4,199
Membership Fees and Dues	1,623
Outside Professional Services	1,372
Directors' Fees and Expenses	113
Miscellaneous	254
TOTAL	$ 7,561

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2005

SCHEDULE XVIII - NOTES TO STATEMENT OF INCOME

Instructions: The space below is provided for important notes regarding the statement of income or any account thereof. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year. Notes related to financial statements shown elsewhere in this report may be indicated here by reference.

1) Page 21 "Analysis of Billing - Associate Companies" captures the category "Compensation for Use of Capital". The following items are included in this category (in thousands):

		2005 (In Thousands)
Interest on Long Term Debt - Notes - Affiliated	$	1,660
Lines of Credit		129
Interest - Associate Companies - Corporate Borrowing Program (Money Pool)		(1,179)
Allowance for Borrowed Funds Used During Construction		(291)
Other Interest Expense		1
Total Compensation for Use of Capital	$	320

2) See Notes to Financial Statements on Page 19.

ANNUAL REPORT OF American Electric Power Service Corporation

For Year Ended December 31, 2005

ORGANIZATION CHART

Chairman, Chief Executive Officer & President

- Audit Services
- Corporate Communications
- Environmental and Safety
- Legal

- AEP Utility Operations
  - AEP Utilities - East
  - AEP Utilities - West
  - Customer Operations
  - Transmission
  - Distribution Services
  - Regulatory Services
  - Commercial Operations

- Generation
  - GBS SVP Business Services
  - Nuclear Generation
  - GET SVP Engineering, Technical & Environmental Services
  - Generation - Fossil & Hydro
  - Fuel, Emissions & Logistics

- Shared Services
  - Human Resources
  - Information Technology
  - Business Logistics

- Finance, Accounting and Strategic Planning
  - Corporate Accounting, Planning/Strategy
  - Risk Management
  - Investor Relations
  - Corporate Accounting
  - Corporate Planning & Budgeting
  - Corporate Finance

NOTE: Audit Services reports to the Audit Committee of the Board of Directors of American Electric Power Company, Inc. and administratively to the Chairman, Chief Executive Officer & President.

METHODS OF ALLOCATION

Service Billings

1	Number of Bank Accounts
2	Number of Call Center Telephones
3	Number of Cell Phones/Pagers
4	Number of Checks Printed
5	Number of Customer Information System Customer Mailings
6	Number of Commercial Customers (Ultimate)
7	Number of Credit Cards
8	Number of Electric Retail Customers (Ultimate)
9	Number of Employees
10	Number of Generating Plant Employees
11	Number of General Ledger Transactions
12	Number of Help Desk Calls
13	Number of Industrial Customers (Ultimate)
14	Number of Job Cost Accounting Transactions
15	Number of Non-UMWA Employees
16	Number of Phone Center Calls
17	Number of Purchase Orders Written
18	Number of Radios (Base/Mobile/Handheld)
19	Number of Railcars
20	Number of Remittance Items
21	Number of Remote Terminal Units
22	Number of Rented Water Heaters
23	Number of Residential Customers (Ultimate)
24	Number of Routers
25	Number of Servers
26	Number of Stores Transactions
27	Number of Telephones
28	Number of Transmission Pole Miles
29	Number of Transtext Customers
30	Number of Travel Transactions
31	Number of Vehicles
32	Number of Vendor Invoice Payments
33	Number of Workstations
34	Active Owned or Leased Communication Channels
35	Avg. Peak Load for past Three Years
36	Coal Company Combination
37	AEPSC past 3 Months Total Bill Dollars
38	AEPSC Prior Month Total Bill Dollars
39	Direct
40	Equal Share Ratio
41	Fossil Plant Combination
42	Functional Department's Past 3 Months Total Bill Dollars
43	KWH Sales (Ultimate Customers)
44	Level of Construction - Distribution
45	Level of Construction - Production
46	Level of Construction - Transmission
47	Level of Construction - Total
48	MW Generating Capability
49	MWH's Generation
50	Current Year Budgeted Salary Dollars
51	Past 3 Mo. MMBTU's Burned (All Fuel Types)
52	Past 3 Mo. MMBTU's Burned (Coal Only)
53	Past 3 Mo. MMBTU's Burned (Gas Type Only)
54	Past 3 Mo. MMBTU's Burned (Oil Type Only)

METHODS OF ALLOCATION

Service Billings

55	Past 3 Mo. MMBTU's Burned (Solid Fuels Only)
56	Peak Load / Avg. No. Cust / KWH Sales Combination
57	Tons of Fuel Acquired
58	Total Assets
59	Total Assets less Nuclear Plant
60	AEPSC Annual Costs Billed (Less Interest And/or Income Taxes as Applicable)
61	Total Fixed Assets
62	Total Gross Revenue
63	Total Gross Utility Plant (Including CWIP)
64	Total Peak Load (Prior Year)
65	Hydro MW Generating Capability
66	Number of Forrest Acres
67	Number of Banking Transactions
68	Number of Dams
69	Number of Plant Licenses Obtained
70	Number of Nonelectric OAR Invoices
71	Number of Transformer Transactions
72	Tons of FGD Material
73	Tons of Limestone Received
74	Total Assets, Total Revenues, Total Payroll
75	Total Leased Assets

ANNUAL STATEMENT OF COMPENSATION FOR USE OF CAPITAL BILLED

Since this FERC Form 60 report is distributed to the appropriate members of AEP's management each year, they are receiving notification concerning the amount of compensation for use of capital billed during 2005.

American Electric Power Service Corporation submits the following information on the billing of interest on borrowed funds to associated companies for the year 2005:

A. Amount of interest billed to associate companies for working capital is contained on page 21, Analysis of Billing - Associate Companies.

B. The basis for billing of interest to the associated companies is based on the Service Company's prior year Attribution Basis "AEPSC Annual Costs Billed ."

KY. PUBLIC SERVICE COMMISSION

Index for Case: 1999-00149

AS OF : 05/17/02

American Electric Power

Transfer / Sale / Purchase / Merger

Regular

OF KENTUCKY POWER & CENTRAL AND SOUTH WEST CORPORATION

IN THE MATTER OF THE JOINT APPLICATION OF KENTUCK POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER

SEQ NBR		Date	Remarks
1	(M)	04/14/99	MOTION TO ENTER PROCEDURAL ORDER & TO SCHEDULE INFORMAL CONFERENCE (MARK OVERSTREET / KENTUCKY POWER)
2		04/15/99	Application.
3		04/15/99	Acknowledgement letter.
4		04/20/99	Order setting forth the procedural schedule to be followed in this case.
5		04/22/99	No deficiency letter.
6	(M)	04/22/99	MOTION TO INTERVENE (E BLACKFORD AG)
7	(M)	04/22/99	DUPLICATE OF NOTICE AND REQUEST TO PUBLISH (ERROL WAGNER AMERICAN ELECTIRC POWER)
8	(M)	04/23/99	STIPULATION & SETTLEMENT AGREEMENT (PSC)
9	(M)	04/27/99	LETTER CONCERNING MEETING ON MAY 4,99 & REQ FOR ORDER TO BE ENTERED (MARK OVERSTREET)
10	(M)	04/27/99	MOTION TO INTERVENE (KES SMITTY TAYLOR)
11		04/28/99	Data Request Order; info due 5/4/99 from KPC, AEP and Central & So. West Corp.
12	(M)	04/28/99	REQUEST FOR INFORMATION TO KY POWER CO & AMERICAN ELETRIC POWER (AG E BLACKFORD)
13	(M)	04/28/99	JOINT APPLICANTS RESP TO STAFF ORAL DATA REQ 2-4 MADE APRIL 22,99 (MARK OVERSTREET KY POWER,AMMERICAN E)
14	(M)	04/29/99	ASSESMENT OF GENERATION & TRANSMISSION ADEQUACY (KY POWER & AMERICAN ELECTRIC POWER)
15		04/30/99	Order scheduling IC on 5/4/99 at 9:30 in Hearing Room 2.
16		05/04/99	Order granting motion of Attorney General for full intervention.
17		05/04/99	Order granting motion of Kentucky Electric Steel for full intervention.
18	(M)	05/04/99	PETITION TO INTERVENE (DAVID BOEHM KIUC)
19	(M)	05/04/99	RESPONSE TO INFO REQ DATED APRIL 28,99 (MARK OVERSTREET KY POWER)
20		05/07/99	Letter granting pet. for conf. filed 4/29/99 on behalf of AEP and KPC.
21	(M)	05/07/99	SUPPLEMENTAL RESPONSE TO DATA REQUEST (MARK OVERSTREET / KY POWER)
22		05/11/99	Data Request Order, response due 5/17/99.
23		05/11/99	Order granting motion of the KIUC to intervene.
24	(M)	05/11/99	SECOND REQUEST FOR INFO. PROPOUNDED BY THE A.G. (ELIZABETH BLACKFORD ASS. ATTORN. GEN)
25		05/14/99	Order scheduling IC on 5/17/99 at 9:30 in Hearing Room 2.
26	(M)	05/14/99	MOTION FOR FULL INTERVENTION (J D MYLES KY ASSOC OF PLUMBING HEAT)
27	(M)	05/17/99	RESPONSE TO PSC INFO REQ DATED MAY 11,99 (MARK OVERSTREET KY POWER)
28	(M)	05/18/99	OPPOSITION OF JOINT APPLICATNS TO MOTION OF KY ASSOCIATION (MARK OVERSTREET KENTUCKY POWER)
29		05/19/99	Order scheduling IC on 5-20-99 at 2p.m. in Hearing Room 2.
30		05/20/99	Order denying the Contractors' motion to intervene
31	(M)	05/24/99	STIPULATION & SETTLEMENT AGREEMENT (MARK OVERSTREET)
32	(M)	05/26/99	DIRECT TESTIMONY OF RICHARD MUNCZINSKI (MARK OVERSTREET AMERICAN ELETRIC POW)
33	(M)	05/26/99	ORIGINAL 16,19,17 PAGES WITH ORIGINAL SIGNATURES (MARK OVERSTREET AMERICAN ELECTRIC PO)
34	(M)	05/27/99	MOTION FOR RECONSIDERATION (JD MYLES ATTORNEY)
35	(M)	06/03/99	OPPOSITION TO JOINT MOTION OF KY ASSOC OF PLUMBING & KY PROPANE (KY POWER & CENTRAL & SOUTH WEST CORP)
36		06/14/99	Final Order approving terms and conditions of attached Settlement Agreement.
37	(M)	06/14/99	Hearing held on 5/28/99. (Connie Sewell/Court Reporter)
38	(M)	07/02/99	REVISED TARIFF (MARK OVERSTREET AMERICAN ELELCTRIC P)
39	(M)	12/08/00	Errol K Wagner - American Electric Power - AEP's responses to the information requests pursuant to the Commission's Order dated June 14, 1999.
40	(M)	01/31/01	COPY OF LETTER INTENDS TO SERVE TO SECURITIES & EXCHANGE COMMISSION (ERROL K. WAGNER AEP)
41		02/22/01	Letter to Errol Wagner, addressing his concerns.
42	(M)	04/18/01	RESPONSE TO ORDER OF FEB 22,01 (ERROL WAGNER AMERICAN ELECTRIC POWER)
43	(M)	05/15/01	RESPONSE TO COMMISSION'S ORDER (MARK OVERSTREET/KY POWER)
44	(M)	08/10/01	Mark R Overstreet - Stites & Harbison - REPORTS FOR THE PERIODS ENDING MARCH 31, 2001 AND JUNE 30, 2001
45	(M)	11/26/01	Response to Commission's Order of June 14, 1999

46 (M) 05/15/02 Mark R Overst[illegible] - Stites & Harbison - Supplementary response to th[illegible]ata request set forth in the Order of June 14,99

STITES & HARBISON

ATTORNEYS

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May 15, 2002

Mark R. Overstreet
[502] 209-1219
moverstreet@stites.com

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

MAY 15 2002

RE: P.S.C. Case No. 99-149

Dear Mr. Dorman:

Please find enclosed and accept for filing the supplementary Responses of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the proceeding described above.

As indicated below, copies have been served this day on the parties to the proceeding. If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

Enclosure

cc: Michael L. Kurtz (w/ enclosure)
David F. Boehm (w/o enclosure)
William H. Jones (w/ enclosure)
Elizabeth E. Blackford (w/ enclosure)

KE057:KE131:7281:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

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

****

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

Reporting Period: Year Ending December 31, 2001
And
Quarter Ending March 31, 2002

Filing Date: 15 May 2002

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Attached you will find a copy of AEP's 2001 combined annual financial statements and the SEC Form 10K (Attachment 1), Form U-13-60 (Attachment 2) and Form U5S (Attachment 3) also for the year 2001. The Form U5S contains the consolidating financial statements of AEP including the consolidation adjustments of AEP and its subsidiaries.

WITNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

A general description of the nature of inter-company transactions is contained in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1. There have been no changes to the procedures used to price inter-company transactions from those used in the prior year. Unless exempted, inter-company transactions conducted by or with Kentucky Power Company are priced at fully-allocated cost in accordance with Rules 90 and 91 prescribed by the Securities and Exchange Commission under the Public Utility Holiday Company Act of 1935.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Attached is a list of Kentucky Power Company employees transferred from Kentucky Power during the twelve months ending December 31, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2001

03

02 APPALACHIAN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
NEWSOME,WILLIAM T	05/12/2001	METER READER X	METER READER X
RICHARDSON,CHARL	11/10/2001	TRANSMISSION LINE CREW SUPV-NE	TRANSMISSION LINE CREW SUPV-NE
STANLEY,CHARLES V	01/01/2001	AREA SUPV FACILITY MGMT	AREA SUPV FACILITY MGMT
THORNSBURY,DONAL	01/01/2001	SUPV FIELD SERVICES	SUPV FIELD SERVICES
TOSTI,RAYMOND M	02/01/2001	CUSTOMER SERVICES FIELD REP SR	CUSTOMER SERVICES FIELD REP SR
VANCE,RICHARD H	10/27/2001	TRANSMISSION LINE MECHANIC-A	TRANSMISSION LINE CREW SUPV-NE
WEBB,HAROLD L	01/01/2001	MGR TRANSMISSION LINE	MGR TRANSMISSION LINE

07 OHIO POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
BREWER,CARLOS E	05/12/2001	STATION MECHANIC-A	STATION CREW SUPERVISOR - NE
SPRADLIN,WILLIAM D	05/12/2001	STATION CREW SUPERVISOR - NE	SUPV STATION CREW

10 COLUMBUS SOUTHERN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
WEAVER,THOMAS F,,II	02/01/2001	SENIOR ENGINEER	SENIOR ENGINEER

61 AEP SERVICE CORPORATION

Name	Eff Date	Job Title - Old	Job Title - New
AYERS,PAUL D	01/01/2001	SR ENGINEERING TECHNOLOGIST	SR ENGINEERING TECHNOLOGIST

BORDERS,KENNETH L	01/01/2001	ENGINEER I	ENGINEER I
BOYD,ANTHONY J	12/22/2001	STATION MANAGER I	STATION MANAGER I
BROWN,LARRY D	12/22/2001	DISTRIBUTION LINE COORDINATOR	DISTRIBUTION LINE COORDINATOR
BURTON,JAMES G	01/01/2001	ENGINEER I	ENGINEER I
BUSCH,BRENT L	12/22/2001	SUPV PROTECTION & CONTROL	SUPV PROTECTION & CONTROL
CHANEY,JACKAWAYN	12/22/2001	ADMINISTRATIVE SECRETARY	ADMINISTRATIVE SECRETARY
DEMPSEY,MARK E	01/01/2001	MGR STATE GOVT AFFAIRS	MGR STATE GOVT AFFAIRS
DILLOW,HAROLD E,,II	02/01/2001	ENGINEER I	ENGINEER I
MAGGARD,CHARLES J	01/01/2001	ENGINEER IV	ENGINEER IV
MCHENRY,MELISSA A	01/01/2001	MGR-STATE CORP COMMS	MGR-STATE CORP COMMS
MUSIC,DONALD	01/01/2001	CUSTOMER SERVICES COORD II	CUSTOMER SERVICES COORD II
PALUMBO,WAYNE	09/29/2001	CUST SVCS ACCT MGR I	ENGINEER I
PARSONS,BART	01/01/2001	ENGINEERING TECHNOLOGIST I	ENGINEERING TECHNOLOGIST I
PERRY,CHARLES E	12/22/2001	SERVICE DISPATCHER III X	SERVICE DISPATCHER III X
PHILLIPS,EVERETT G	12/22/2001	MGR DISTRIBUTION SYSTEM	MGR DISTRIBUTION SYSTEM
PORTER,STEVEN H	01/01/2001	ENGINEER II	ENGINEER II
RATLIFF,JAMES O	01/16/2001	ENGINEER I	SUPV PROJECT DESIGN
ROACH,JON D	01/01/2001	TRANS CONSTR REPR II	TRANS CONSTR REPR II
SODE,JOHN P	12/22/2001	TECHNICIAN SENIOR	TECHNICIAN SENIOR
STANLEY,CHARLES V	12/22/2001	AREA SUPV FACILITY MGMT	AREA SUPV FACILITY MGMT
STRADER,TIMOTHY V	01/01/2001	TRANS CONSTR REPR II	TRANS CONSTR REPR II

TACKETT,CHARLES E	01/01/2001	REVENUE PROTECTION COORD II	REVENUE PROTECTION COORD II
WILSON,NEIL J	01/01/2001	ENGINEER I	ENGINEER I

CC CENTRAL POWER & LIGHT

Name	*Eff Date*	*Job Title - Old*	*Job Title - New*
KLINGLESMITH,WILLIA	11/10/2001	TRANSMISSION LINE MECHANIC-A	LINE TECH A

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

4th Quarter 2001

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees for the 4th Quarter ending December 31, 2001.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

Three Months December 31, 2001 — Twelve Months December 31, 2001

	AEP	KPCO	SHARE		AEP	KPCO	SHARE
Revenues	14,179	265	1.9%	Revenues	61,257	1,617	2.6%
Operating/Maintenance Expense	13,430	221	1.6%	Operating/Maintenance Expense	56,790	1,431	2.5%
Number of Employees At 12/31/01*	22,150	429	1.9%	Number of Employees At 12/31/01*	22,150	429	1.9%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

1st Quarter 2002

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees for the 1st Quarter ending March 31, 2002.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months March 31, 2002				Year to Date March 31, 2002		
	AEP	KPCO	SHARE		AEP	KPCO	SHARE
Revenues	13,414	345	2.6%	Revenues	13,414	345	2.6%
Operating/Maintenance Expense	12,349	291	2.4%	Operating/Maintenance Expense	12,349	291	2.4%
Number of Employees At 03/31/02*	22,490	428	1.9%	Number of Employees At 03/31/02*	22,490	428	1.9%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

4th Quarter 2001:

During the three month period ending December 31, 2001 there were 18 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $79,079.82. The smallest dollar value transferred was one meter at a value of $18.00. The largest dollar value transferred was 506 meters at a value of $26,572.00.

1st Quarter 2002:

During the three month period ending March 31, 2002 there were 19 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $60,815.84. The smallest dollar value transferred was two meters at a value of $18.00. The largest dollar value transferred was 361 meters at a value of $13,253.00.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

Attached are the quarterly reports of the number of employees of AEP and each subsidiary on the basis of payroll assigned for 4th Quarter 2001 and 1st Quarter 2002.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 12/31/2001

4th Quarter 2001

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	58
02	APPALACHIAN POWER COMPANY	2647
03	KENTUCKY POWER POWER COMPANY	429
04	INDIANA MICHIGAN POWER COMPANY	2582
06	WHEELING POWER POWER COMPANY	65
07	OHIO POWER COMPANY	2309
10	COLUMBUS SOUTHERN POWER COMPANY	1187
36	LA INTRASTATE GAS CO, LLC	66
39	LIG LIQUIDS COMPANY, LLC	35
48	RIVER TRANSPORTATION DIV-I&M	331
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	205
61	AEP SERVICE CORPORATION	7239
69	AEP RESOURCES SERVICE COMPANY	76
CC	CENTRAL POWER & LIGHT	1377
EE	CSW ENERGY, INC	91
EL	AEP ELMWOOD, INC	137
HH	ENERSHOP, INC.	4
MM	C3 COMMUNICATIONS	27
MO	AEPMEMCO, INC	294
NW	C3 NETWORKS GP LLC	30
PP	PUBLIC SERVICE CO OF OK	998
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1230
TD	AEP T&D SERVICES, LLC	1
WW	WEST TEXAS UTILITIES	695
	TOTAL	22150

1st Quarter 2002

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 03/31/2002

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	57
02	APPALACHIAN POWER COMPANY	2622
03	KENTUCKY POWER POWER COMPANY	428
04	INDIANA MICHIGAN POWER COMPANY	2588
06	WHEELING POWER POWER COMPANY	64
07	OHIO POWER COMPANY	2295
10	COLUMBUS SOUTHERN POWER COMPANY	1172
36	LA INTRASTATE GAS CO, LLC	65
39	LIG LIQUIDS COMPANY, LLC	36
48	RIVER TRANSPORTATION DIV-I&M	341
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	270
61	AEP SERVICE CORPORATION	7573
69	AEP RESOURCES SERVICE COMPANY	76
CC	CENTRAL POWER & LIGHT	1371
EE	CSW ENERGY, INC	92
EL	AEP ELMWOOD, INC	142
HH	ENERSHOP, INC.	3
MO	AEPMEMCO, INC	315
NW	C3 NETWORKS GP LLC	29
PP	PUBLIC SERVICE CO OF OK	998
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1223
TD	AEP T&D SERVICES, LLC	1
WW	WEST TEXAS UTILITIES	692
	TOTAL	22490

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Attached is the annual report for twelve months ending December 31, 2001 listing the years of service at Kentucky Power Company and the salaries of the professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with Item Number 3.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2001

03

02 APPALACHIAN POWER COMPANY

Name	*Eff Date*	*Total Years of Service*	*Annual Salary*
NEWSOME,WILLIAM T	05/12/2001	12	34,507.20
RICHARDSON,CHARLES R	11/10/2001	28	62,149.88
STANLEY,CHARLES V	01/01/2001	24	53,800.00
THORNSBURY,DONALD J	01/01/2001	34	82,400.00
TOSTI,RAYMOND M	02/01/2001	27	53,400.00
VANCE,RICHARD H	10/27/2001	17	55,000.40
WEBB,HAROLD L	01/01/2001	32	71,300.00

07 OHIO POWER COMPANY

Name	*Eff Date*	*Total Years of Service*	*Annual Salary*
BREWER,CARLOS E	05/12/2001	22	52,520.00
SPRADLIN,WILLIAM D	05/12/2001	15	60,000.00

10 COLUMBUS SOUTHERN POWER COMP

Name	*Eff Date*	*Total Years of Service*	*Annual Salary*
WEAVER,THOMAS F,,III	02/01/2001	23	81,100.00

61 AEP SERVICE CORPORATION

Name	*Eff Date*	*Total Years of Service*	*Annual Salary*
AYERS,PAUL D	01/01/2001	20	69,800.00

BORDERS,KENNETH L	01/01/2001	21	72,300.00
BOYD,ANTHONY J	12/22/2001	24	93,300.00
BROWN,LARRY D	12/22/2001	32	64,200.00
BURTON,JAMES G	01/01/2001	14	66,000.00
BUSCH,BRENT L	12/22/2001	15	80,300.00
CHANEY,JACKAWAYNE R	12/22/2001	30	41,085.20
DEMPSEY,MARK E	01/01/2001	25	93,400.00
DILLOW,HAROLD E,,II	02/01/2001	19	78,700.00
MAGGARD,CHARLES J	01/01/2001	4	44,000.00
MCHENRY,MELISSA A	01/01/2001	6	76,000.00
MUSIC,DONALD	01/01/2001	30	69,500.00
PALUMBO,WAYNE	09/29/2001	22	70,000.00
PARSONS,BART	01/01/2001	11	58,800.00
PERRY,CHARLES E	12/22/2001	25	41,700.00
PHILLIPS,EVERETT G	12/22/2001	16	92,500.00
PORTER,STEVEN H	01/01/2001	12	60,000.00
RATLIFF,JAMES O	01/16/2001	20	77,800.00
ROACH,JON D	01/01/2001	33	63,900.00
SODE,JOHN P	12/22/2001	21	44,270.20
STANLEY,CHARLES V	12/22/2001	24	56,400.00
STRADER,TIMOTHY V	01/01/2001	25	61,900.00
TACKETT,CHARLES E	01/01/2001	20	50,000.00

WILSON,NEIL J	01/01/2001	28	75,400.00

CC CENTRAL POWER & LIGHT

Name	*Eff Date*	*Total Years of Service*	*Annual Salary*
KLINGLESMITH,WILLIAM S	11/10/2001	13	49,628.80

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

The cost allocation factors used by Kentucky Power Company and other AEP System companies are described in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2. AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149).

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

Kentucky Power Company did not perform any cost allocation studies during the year ended December 31, 2001. The methods used by Kentucky Power Company for cost allocations are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

The methods used to update or revise the cost allocation factors used by Kentucky Power Company and other AEP System companies were not significantly changed during the year ended December 31, 2001. Allocation factors are revised periodically each year (e.g., monthly, quarterly, semi-annually and annually) based on the most current statistics available for each factor. The allocation factors in use are documented in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2.

AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149).

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item 11 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item 11 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

There were no changes during the period ending December 31, 2001 to the terms and conditions of the settlements in any jurisdiction which would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nation clause.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

See the Company's response to Item 14 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2001. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

The overall Customer Average Interruption Duration Index (CAIDI), including major events, for Kentucky Power Company (KPCo) customers during calendar 2001 was 4.51 hours per customer interrupted. The overall System Average Interruption Frequency Index (SAIFI), including major events, for KPCo customers during calendar 2001 was 2.16 interruptions per customer served.

Both of these indices are higher than the 1995-1998 averages for these customers. The two main reasons being the change in outage recording systems and a greater influence of major storms in calendar 2001.

KPCo has previously reported on its changes in outage recording systems. Making comparisons to the 1995-1998 values is very difficult because of the numerous advancements in outage recording technology. The ultimate result is more accurate outage customer count and outage duration values. Any possible worsening of reliability indices is greatly exaggerated because of the refinements in the recording process.

The other influence on the reliability indices for KPCo customers was the impact of major storms. Although both SAIFI and CAIDI including storms were higher in Y2001 than the 1995-1998 average, the CAIDI was actually a little lower and the SAIFI was closer to the earlier average when excluding major storms.

KPCo has stated some of the reasons beyond the storm challenges and recording changes in other proceedings.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2000. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

A summary of AEP's Call Center Performance Measures for Kentucky customer calls in calendar year 2001:

Measure	Value
Average Speed of answer	38.68 seconds
Abandonment	3.87%
Network Blockage	.34%

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2001.
[Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Note: This is not a new reporting requirement – the Company has been conducting inspections and making necessary improvements for years.

In calendar year 2001, American Electric Power performed the work necessary to completely inspect its Kentucky electric facilities over the two-year period 2001-2002. AEP continues to perform tree trimming, lightning arrester replacement, animal guarding, and pole and cross arm replacements as needed.

AEP provides the following statistics for work done in its Kentucky service territory in 2001.

- Performed walking inspections of approximately 102,315 poles as part of the program to inspect facilities every two years. Equipment was repaired or replaced as necessary.
- Inspected 9,677 poles as part of the ground-line treatment program. Poles were replaced or refurbished as necessary.
- Completed right-of-way maintenance work on 1,151 miles of distribution line.

AEP continues its asset management programs to review the performance of its facilities and to make prudent improvements to continue providing reliable and cost-effective electric service to its Kentucky customers.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impacts of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages.
[Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

AEP-Kentucky continues to compile outage data detailing each circuit's reliability performance. Worst performing circuits are identified considering CAIDI, SAIFI, and repeat outages, as well as those with outage causes that can be addressed through existing asset improvement programs targeting animal, lightning, small conductor failure, and tree caused outages. This allows for the identification of areas needing reliability improvements and for the development of work plans to optimize system performance where within utility control.

Work plans are developed by combining reliability performance with input from field personnel to identify areas that do not satisfy ranking criteria alone. Work plans include ground line treatment of poles; improved fault isolation by installing additional sectionalizing devices; recloser maintenance; and system improvements required due to facility loading, voltage control, and reliability performance.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

The Company has maintained a high quality workforce which met the customers needs in providing electrical service.

WITNESS: Errol K. Wagner

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, is the contact designee for the Kentucky Public Service Commissioners and Staff and the Kentucky Attorney General's Office regarding affiliate transactions and personnel transfers.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

The Company would prefer customers to initially call the Customer Solution Centers, whose representatives are capable of answering questions concerning service, reliability concerns and billing issues. However, the AEP-Kentucky Regulatory Services Department, specifically the Regulatory Services Director, are also capable of dealing with billing, maintenance and service reliability issues.

WITNESS: Errol K. Wagner

22

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, and the AEP-Kentucky Regulatory Services Department staff are the designated employees to work with Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

The Company has maintained a sufficient management team in Kentucky to ensure that safe, reliable and efficient electric service is provided and the Company has responded to the needs and inquiries of its customers.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State Commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger. [Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE:

Kentucky Power Company continues to adhere to all applicable affiliate standards. In light of the General Assembly's enactment of HB 897 (KRS 278.2201 et seq.) in 2000, and the express terms of the Merger Settlement Agreement and the Order approving the agreement, the affiliate standards and requirements contained in the Merger Settlement Agreement have been superseded by statute. *See, Order, Joint Application of Kentucky Power Company, American Electric Power Company, Inc., and Central and South West Corporation Regarding a Proposed Merger, P.S.C. Case No. 99-149 at 8 (affiliate standards and guidelines set out in Merger Settlement Agreement to "remain in effect 'until new affiliate standards imposed by either the Commission or by the General Assembly.'".)* Accordingly, Kentucky Power Company will not be conducting a biennial audit of affiliated transactions as contemplated by the now superseded standards.

WITNESS: Errol K. Wagner

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2001

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
0-346	CENTRAL POWER AND LIGHT COMPANY (A Texas Corporation)	74-0550600
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
0-340	WEST TEXAS UTILITIES COMPANY (A Texas Corporation)	75-0646790
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 223-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ✓. No.

Indicate by check mark if disclosure of delinquent filers with respect to American Electric Power Company, Inc. pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company. Indiana Michigan Power Company or Ohio Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements of Appalachian Power Company or Ohio Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ✓

AEP Generating Company, Columbus Southern Power Company, Kentucky Power Company, Public Service Company of Oklahoma and West Texas Utilities Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
AEP Generating Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	8-1/4% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026	New York Stock Exchange
	8% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New York Stock Exchange
	7.20% Senior Notes, Series A, Due 2038	New York Stock Exchange
	7.30% Senior Notes, Series B, Due 2038	New York Stock Exchange
Columbus Southern Power Company	8-3/8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
	7.92% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New York Stock Exchange
CPL Capital I	8.00% Cumulative Quarterly Income Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange
Indiana Michigan Power Company	8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026	New York Stock Exchange
	7.60% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2038	New York Stock Exchange
Kentucky Power Company	8.72% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
Ohio Power Company	8.16% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
	7.92% Junior Subordinated Deferrable Interest Debentures Series B, Due 2027	New York Stock Exchange
	7-3/8% Senior Notes, Series A, Due 2038	New York Stock Exchange
PSO Capital I	8.00% Trust Originated Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange
SWEPCo Capital I	7.875% Trust Preferred Securities, Series A, Liquidation amount $25 per Preferred Security	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
AEP Generating Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	None
Central Power and Light Company	4.00% Cumulative Preferred Stock, Non-Voting, $100 par value 4.20% Cumulative Preferred Stock, Non-Voting, $100 par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	4.125% Cumulative Preferred Stock, Non-Voting, $100 par value
Kentucky Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value 4.65% Cumulative Preferred Stock, Non-Voting, $100 par value 5.00% Cumulative Preferred Stock, Non-Voting, $100 par value
West Texas Utilities Company	None

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants at February 1, 2002	Number of shares of common stock outstanding of the registrants at February 1, 2002
AEP Generating Company	None	1,000 ($1,000 par value)
American Electric Power Company, Inc.	$13,478,213,062	322,368,167 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Central Power and Light Company	None	6,755,535 ($25 par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)
West Texas Utilities Company	None	5,488,560 ($25 par value)

NOTE ON MARKET VALUE OF COMMON EQUITY HELD BY NON-AFFILIATES

American Electric Power Company, Inc. owns, directly or indirectly, all of the common stock of AEP Generating Company, Appalachian Power Company, Central Power and Light Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company (see Item 12 herein).

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2001: AEP Generating Company American Electric Power Company, Inc. Appalachian Power Company Central Power and Light Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company West Texas Utilities Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2002 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2001	Part III
Portions of Information Statements of the following companies for 2002 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2001: Appalachian Power Company Ohio Power Company	Part III

This combined Form 10-K is separately filed by AEP Generating Company, American Electric Power Company, Inc., Appalachian Power Company, Central Power and Light Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AFUDC	Allowance for funds used during construction. Defined in regulatory systems of accounts as the net cost of borrowed funds used for construction and a reasonable rate of return on other funds when so used.
APCo	Appalachian Power Company, an electric utility subsidiary of AEP.
Btu	British thermal unit.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
C3	C3 Communications, Inc.
CAA	Clean Air Act.
CAAA	Clean Air Act Amendments of 1990.
CCD Group	CSPCo, CG&E and DP&L.
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company.
CO_2	Carbon dioxide.
Cook Plant	The Donald C. Cook Nuclear Plant, owned by I&M, located near Bridgman, Michigan.
CPL	Central Power and Light Company, an electric utility subsidiary of AEP.
CSPCo	Columbus Southern Power Company, an electric utility subsidiary of AEP.
CSW	Central and South West Corporation.
DOE	United States Department of Energy.
DP&L	The Dayton Power and Light Company, an unaffiliated utility company.
East Zone Companies of AEP	APCo, CSPCo, I&M, KEPCo and OPCo.
ERCOT	Electric Reliability Council of Texas.
EWG	Exempt wholesale generator.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission (an independent commission within the DOE).
FUCO	Foreign utility company as defined by PUHCA.
I&M	Indiana Michigan Power Company, an electric utility subsidiary of AEP.
IURC	Indiana Utility Regulatory Commission.
KEPCo	Kentucky Power Company, an electric utility subsidiary of AEP.
MTM	Mark-to-market.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NRC	Nuclear Regulatory Commission.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an electric utility subsidiary of AEP.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated biphenyls.

Abbreviation or Acronym	Definition
PSO	Public Service Company of Oklahoma, an electric utility subsidiary of AEP.
PUCO	The Public Utilities Commission of Ohio.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
QF	Qualifying facility as defined in the Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Rockport Plant	A generating plant, consisting of two 1,300,000-kilowatt coal-fired generating units, near Rockport, Indiana.
SEC	Securities and Exchange Commission.
SEEBOARD	SEEBOARD Group plc, Crawley, West Sussex, United Kingdom.
Service Corporation	American Electric Power Service Corporation, a service subsidiary of AEP.
SO_2	Sulfur dioxide.
SO_2 Allowance	An allowance to emit one ton of sulfur dioxide granted under the Clean Air Act Amendments of 1990.
SPP	Southwest Power Pool.
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.
SWEPCo	Southwestern Electric Power Company, an electric utility subsidiary of AEP.
TVA	Tennessee Valley Authority.
Vale	Empresa De Electricidade Vale Paranapanema SA, a Brazilian Electric Distribution Company.
VEPCo	Virginia Electric and Power Company, an unaffiliated utility company.
Virginia SCC	Virginia State Corporation Commission.
West Virginia PSC	Public Service Commission of West Virginia.
West Zone Companies of AEP	CPL, PSO, SWEPCo and WTU.
WTU	West Texas Utilities Company, an electric utility subsidiary of AEP.
Zimmer or Zimmer Plant	Wm. H. Zimmer Generating Station, a 1,300,000-kilowatt coal-fired generating unit commonly owned by CSPCo (25.4%), CG&E (46.5%) and DP&L (28.1%), and operated by CG&E.

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward-looking statements are:

- Electric load and customer growth.
- Abnormal weather conditions.
- Available sources of and prices for coal and gas.
- Availability of generating capacity.
- Litigation concerning AEP's merger with CSW.
- The timing of the implementation of AEP's restructuring plan.
- Risks related to energy trading and construction under contract.
- The speed and degree to which competition is introduced to our power generation business.
- The ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states.
- New legislation and government regulations.
- The structure and timing of a competitive market for electricity and its impact on prices.
- The ability of AEP to successfully control its costs.
- The success of new business ventures.
- International developments affecting AEP's foreign investments.
- The effects of fluctuations in foreign currency exchange rates.
- The economic climate and growth in AEP's service and trading territories, both domestic and foreign.
- The ability of AEP to comply with or to challenge successfully new environmental regulations and to litigate successfully claims that AEP violated the CAA.
- Inflationary trends.
- Changes in electricity and gas market prices and interest rates.
- Other risks and unforeseen events.

PART I

Item 1. **Business**

General

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, directly or indirectly, all of the outstanding common stock of its domestic electric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the marketing and trading of power and gas and the furnishing of electric service.

The service area of AEP's domestic electric utility subsidiaries covers portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, 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, which do business as "American Electric Power," have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers.

At December 31, 2001, the subsidiaries of AEP had a total of 27,726 employees. AEP, as such, has no employees. The operating subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 917,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying electric power at wholesale to other electric utility companies and municipalities in those states and in Tennessee. At December 31, 2001, APCo and its wholly owned subsidiaries had 2,629 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and VEPCo. A comparatively small part of the properties and business of APCo is located in the northeastern end of the Tennessee Valley. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems.

CPL (organized in Texas in 1945) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 689,000 customers in southern Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2001, CPL had 1,374 employees. Among the principal industries served by CPL are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 678,000 customers in Ohio, and in supplying electric power at wholesale to other electric utilities and to municipally owned distribution systems within its service area. At December 31, 2001, CSPCo had 1,222 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company.

I&M (organized in Indiana in 1925) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 567,000 customers in northern and eastern Indiana and southwestern Michigan, and in supplying electric power at wholesale to other electric utility companies, rural electric cooperatives and municipalities. At December 31, 2001, I&M had 2,851 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company.

KEPCo (organized in Kentucky in 1919) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 173,000 customers in an area in eastern Kentucky, and in supplying electric power at wholesale to other utilities and municipalities in Kentucky. At December 31, 2001, KEPCo had 427 employees. In addition to its AEP System interconnections, KEPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KEPCo is also interconnected with TVA.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 45,000 customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from APCo. At December 31, 2001, Kingsport Power Company had 58 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 698,000 customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying electric power at wholesale to other electric utility companies and municipalities. At December 31, 2001, OPCo and its wholly owned subsidiaries had 2,297 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company.

PSO (organized in Oklahoma in 1913) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 502,000 customers in eastern and southwestern Oklahoma, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2001, PSO had 989 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 431,000 customers in northeastern Texas, northwestern Louisiana, and western Arkansas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2001, SWEPCo had 1,375 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 customers in northern West Virginia. Wheeling Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from OPCo. At December 31, 2001, Wheeling Power Company had 64 employees.

WTU (organized in Texas in 1927) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 189,000 customers in west and central Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2001, WTU had 689 employees. The principal industry served by WTU is agriculture. The territory served by WTU also includes several military installations and correctional facilities.

Another principal electric utility subsidiary of AEP is AEGCo, which was organized in Ohio in 1982 as an electric generating company. AEGCo sells power at wholesale to I&M and KEPCo. AEGCo has no employees.

See Item 2 for information concerning the properties of the subsidiaries of AEP.

The Service Corporation provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and its public utility subsidiaries are all employees of the Service Corporation.

The AEP System is an integrated electric utility system and, as a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity, transportation and handling of fuel, sales or rentals of property and interest or dividend payments on the securities held by the companies' respective parents.

AEP-CSW Merger

On June 15, 2000, CSW merged with and into a wholly owned merger subsidiary of AEP with CSW being the surviving corporation. The merger was pursuant to an Agreement and Plan of Merger, dated as of December 21, 1997, that AEP and CSW had entered into. As a result of the merger, each outstanding share of common stock, par value $3.50 per share, of CSW (other than shares owned by AEP or CSW) was converted into 0.6 of a share of common stock, par value $6.50 per share, of AEP. CSW's four wholly-owned domestic electric utility subsidiaries are CPL, PSO, SWEPCo and WTU.

AEP is complying or intends to comply with the following conditions imposed by the FERC as part of the FERC's order approving the merger:

- Transfer operational control of AEP's east and west transmission systems to fully-functioning, FERC-approved regional transmission organizations. See *Transmission Services for Non-Affiliates.*
- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system. AEP implemented these measures upon the consummation of the merger.
- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT. AEP must complete divestiture of the SPP capacity by July 1, 2002. AEP has completed divestiture of the ERCOT capacity.

The FERC found that certain energy sales of SPP and ERCOT capacity would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. As required by the FERC, the proposed interim energy sales were in effect when the merger was consummated.

Litigation: On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the merger met the requirements of PUHCA and remanded the case to the SEC for further review. The court held that the SEC must explain its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and justify its finding that the merger will result in a combined entity that is confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that AEP's and CSW's systems are interconnected because they have transmission access rights to a single high-voltage line through Missouri and also meet the PUHCA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the court held that the SEC failed to explain its conclusions that the transmission integration and single region requirements are satisfied.

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

Regulation

General

AEP and its subsidiaries are subject to the broad regulatory provisions of PUHCA administered by the SEC. The public utility subsidiaries' retail rates and certain other matters are subject to regulation by the public utility commissions of the states in which they operate. Such subsidiaries are also subject to regulation by the FERC under the Federal Power Act in respect of rates for interstate sale at wholesale and transmission of electric power, accounting and other matters and construction and operation of hydroelectric projects. I&M and CPL are subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant and STP, respectively.

Possible Change to PUHCA

The provisions of PUHCA, administered by the SEC, regulate all aspects of a registered holding company system, such as the AEP System. PUHCA requires that the operations of a registered holding company system be limited to a single integrated public utility system and such other businesses as are incidental or necessary to the operations of the system. In addition, PUHCA governs, among other things, financings, sales or acquisitions of assets and intra-system transactions.

On June 20, 1995, the SEC released a report from its Division of Investment Management recommending a conditional repeal of PUHCA, including its limits on financing and on geographic and business diversification. Specific federal authority, however, would be preserved over access to the books and records of registered holding company systems, audit authority over registered holding companies and their subsidiaries and oversight over affiliate transactions. This authority would be transferred to the FERC. Following the report, legislation was introduced in Congress to repeal PUHCA and transfer certain federal authority to the FERC as recommended in the SEC report. Since 1997, such PUHCA repeal language has been reintroduced in each session of Congress both as a separate bill and as part of broader legislation regarding changes in the electric industry. Legislative hearings were held but neither the House of Representatives nor the Senate passed any PUHCA repeal legislation. A number of bills contemplating PUHCA repeal separately and with the restructuring of the electric utility industry have been introduced in the current Congress. See *Competition and Business Change*. If PUHCA is repealed, registered holding company systems, including the AEP System, will be able to compete in the changing industry without the constraints of PUHCA. Management of AEP believes that removal of these constraints would be beneficial to the AEP System.

PUHCA and the rules and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost with limited exceptions. Over the years, the AEP System has developed numerous affiliated service, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

Conflict of Regulation

Public utility subsidiaries of AEP can be subject to regulation of the same subject matter by two or more jurisdictions. In such situations, it is possible that the decisions of such regulatory bodies may conflict or that the decision of one such body may affect the cost of providing service, and so the rates, in another jurisdiction. In a case involving OPCo, the U.S. Court of Appeals for the District of Columbia held that the determination of costs to be charged to associated companies by the SEC under PUHCA precluded the FERC from determining that such costs were unreasonable for ratemaking purposes. The U.S. Supreme Court also has held that a state commission may not conclude that a FERC approved wholesale power agreement is unreasonable for state ratemaking purposes. Certain actions that would overturn these decisions or otherwise affect the jurisdiction of the SEC and FERC are under consideration by the U.S. Congress and these regulatory bodies. Such conflicts of jurisdiction often result in litigation and, if resolved adversely to a public utility subsidiary of AEP, could have a material adverse effect on the results of operations or financial condition of such subsidiary or AEP.

Rates

The rates charged by the electric utility subsidiaries of AEP are approved by the FERC or one of the state utility commissions as applicable. The FERC regulates wholesale rates and the state commissions regulate retail rates. In recent years the number of rate increase applications filed by the operating subsidiaries of AEP with their respective state commissions and the FERC has decreased. Under current rate regulation, if increases in operating, construction and capital costs exceed increases in revenues resulting from previously granted rate increases and increased customer demand, then it may be appropriate for certain of AEP's electric utility subsidiaries to file rate increase applications in the future.

Generally the rates of AEP's operating subsidiaries are determined based upon the cost of providing service including a reasonable return on investment, except for the states of Ohio, Texas and Virginia as noted below. Certain states served by the AEP System allow alternative forms of rate regulation in addition to the traditional cost-of-service approach. However, the rates of AEP's operating subsidiaries in those states continue to be cost-based. The IURC may approve alternative regulatory plans which could include setting customer rates based on market or average prices, price caps, index-based prices and prices based on performance and efficiency.

AEP is exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT power grid area of Texas (effective January 1, 2002) or frozen by settlement agreements in Indiana, Michigan, and West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts, AEP is subject to market price risk. AEP continues to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas.

AEP cannot predict the timing or probability of approvals regarding applications for additional rate changes, the outcome of action by regulatory commissions or courts with respect to such matters, or the effect thereof on the earnings and business of the AEP System. In addition, current rate regulation may, and in the case of Ohio, Texas and Virginia has been, subject to significant revision. See *Competition and Business Change* and the footnote to the financial statements entitled *Customer Choice and Industry Restructuring.*

Classes of Service

The principal classes of service from which the domestic electric utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2001 are as follows:

	AEP System(a)	AEGCo	APCo (in thousands)	CPL	CSPCo
Wholesale Business:					
Residential	$ 3,553,216	$ 0	$ 587,062	$ 660,884	$ 477,341
Commercial	2,328,383	0	267,312	473,337	426,444
Industrial	2,388,354	0	353,070	345,071	141,583
Other Retail Customers	419,232	0	77,258	49,007	46,948
Energy Delivery	(3,356,000)	0	(575,036)	(473,182)	(483,219)
Total Retail	5,333,185	0	709,666	1,055,117	609,097
Marketing and Trading-Electricity	35,339,641	227,338	5,571,750	1,671,686	3,117,136
Marketing and Trading-Gas	14,368,857	0	0	0	0
Unrealized MTM Income:					
Electric	209,660	0	29,334	19,930	16,730
Gas	46,990	0	0	0	0
Other	631,016	210	113,644	101,812	73,681
Total Wholesale Business	55,929,349	227,548	6,424,394	2,848,545	3,816,644
Energy Delivery Business:					
Transmission	1,029,000	0	180,244	162,734	109,824
Distribution	2,327,000	0	394,792	310,448	373,395
Total Energy Delivery	3,356,000	0	575,036	473,182	483,219
Other Investments:					
SEEBOARD	1,451,233	0	0	0	0
CitiPower	349,773	0	0	0	0
Other	170,645	0	0	0	0
Total Other Investments	1,971,651	0	0	0	0
Total Revenues	$ 61,257,000	$ 227,548	$ 6,999,430	$ 3,321,727	$ 4,299,863

	I&M	KEPCo	OPCo (in thousands)	PSO	SWEPCo	WTU
Wholesale Business:						
Residential	$ 350,600	$ 109,882	$ 444,418	$ 381,515	$ 321,022	$ 160,520
Commercial	218,818	47,369	235,220	305,525	226,946	98,153
Industrial	323,157	92,215	526,431	215,038	273,096	60,032
Other Retail Customers	59,983	16,058	68,968	12,746	33,271	44,318
Energy Delivery	(314,410)	(134,619)	(552,713)	(261,877)	(333,004)	(169,036)
Total Retail	638,148	130,905	722,324	652,947	521,331	193,987
Marketing and Trading-Electricity	3,783,302	1,364,877	4,848,386	1,258,861	1,653,208	648,527
Marketing and Trading-Gas	0	0	0	0	0	0
Unrealized MTM Income:						
Electric	0	0	23,139	0	10,830	4,390
Gas	0	0	0	0	0	0
Other	67,765	28,994	115,840	27,564	56,075	48,331
Total Wholesale Business	4,489,215	1,524,776	5,709,689	1,939,372	2,241,444	895,235
Energy Delivery Business:						
Transmission	122,345	53,697	167,399	63,045	81,324	75,443
Distribution	192,065	80,922	385,314	198,832	251,680	93,593
Total Energy Delivery	314,410	134,619	552,713	261,877	333,004	169,036
Other Investments:						
SEEBOARD	0	0	0	0	0	0
CitiPower	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total Other Investments	0	0	0	0	0	0
Total Revenues	$ 4,803,625	$ 1,659,395	$ 6,262,402	$ 2,201,249	$ 2,574,448	$ 1,064,271

(a) Includes revenues of other subsidiaries not shown and elimination of intercompany transactions.

Sale of Power

AEP's electric utility subsidiaries own or lease generating stations with total generating capacity of approximately 38,300 megawatts. See Item 2. *Properties,* for more information regarding the generating stations. They operate their generating plants as a single interconnected and coordinated electric utility system and, in the east zone, share the costs and benefits in the AEP System Power Pool. As discussed below under *AEP System Power Pool,* after corporate separation, the public utility subsidiaries that are no longer regulated at the state level will participate in a separate power pool. Most of the electric power generated at AEP's generating stations is sold, in combination with transmission and distribution services, to retail customers of AEP's utility subsidiaries in their service territories. See *Regulation—Rates.* Some of the electric power is sold at wholesale to non-affiliated companies.

AEP System Power Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO_2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with the FERC, CSPCo and OPCo would no longer be parties to the Interconnection Agreement and certain other modifications to its terms would also be made. See *Competition and Business Change—AEP Restructuring Plan.*

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement. Trading activities involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The regulated physical forward contracts are recorded on a gross basis in the month when the contract settles.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

The following table shows the net credits or (charges) allocated among the parties under the Interconnection Agreement and Interim Allowance Agreement during the years ended December 31, 1999, 2000 and 2001:

	1999(a)	2000(a) (in thousands)	2001(a)
APCo	$(89,100)	$(274,000)	$(256,700)
CSPCo	(184,500)	(250,400)	(251,200)
I&M	(61,700)	93,900	166,200
KEPCo	23,700	(21,500)	(27,600)
OPCo	311,600	452,000	369,300

(a) Includes credits and charges from allowance transfers related to the transactions.

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. As part of AEP's restructuring settlement agreement filed with the FERC, CPL and WTU would no longer be parties to the CSW Operating Agreement and certain other modifications to its terms would also be made. See *Competition and Business Change—AEP Restructuring Plan.*

Wholesale Sales of Power to Non-Affiliates

AEP's electric utility subsidiaries also sell electric power on a wholesale basis to non-affiliated electric utilities and power marketers. Such sales are either made (i) by individual companies pursuant to various long-term power agreements or (ii) under the Interconnection Agreement (AEP Power Pool) or the CSW Operating Agreement. Sales made under the Interconnection Agreement are allocated among the East Zone subsidiaries based on member-load ratios. Sales made under the CSW Operating Agreement are allocated among the West Zone subsidiaries based on participation ratios.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* that is incorporated by reference in Item 8 for information with respect to AEP's long-term agreements to sell power.

Transmission Services

AEP's electric utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 for more information regarding the transmission and distribution lines. AEP's electric utility subsidiaries operate their transmission lines as a single interconnected and coordinated system and share the cost and benefits in the AEP System Transmission Pool. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See *Regulation—Rates*. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP System Transmission Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kv and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio." See *Sale of Power.*

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1999, 2000 and 2001:

	1999	2000	2001
		(in thousands)	
APCo..........	$(8,300)	$(3,400)	$(3,100)
CSPCo	39,000	38,300	40,200
I&M............	(43,900)	(43,800)	(41,300)
KEPCo........	(4,300)	(6,000)	(4,600)
OPCo..........	17,500	14,900	8,800

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

Transmission Services for Non-Affiliates

AEP's electric utility subsidiaries and other System companies also provide transmission services for non-affiliated companies.

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

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of regional transmission organizations (RTOs), entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals.

On July 9, 1996, the AEP System companies filed a tariff conforming with the FERC's *pro-forma* transmission tariff.

Since 1998 AEP has engaged in discussions with a group of Midwestern utilities regarding the development of the Alliance RTO which may take the form of an ISO or an independent transmission company (Transco), depending upon the occurrence of certain conditions. The Transco, if formed, would operate transmission assets that it would own, and also would operate other owners' transmission assets on a contractual basis.

In 2001 the Alliance companies filed with the FERC a proposed business plan for the Alliance RTO. In December 2001, the FERC issued an order approving the proposal of the Midwest ISO (an independent operator of transmission assets in the Midwest) for an RTO and rejecting the Alliance RTO's business plan and finding that the Alliance RTO lacks sufficient scope and regional configuration to exist as a stand-alone RTO. The FERC directed the Alliance companies to negotiate with the Midwest ISO and others to explore possible combinations. Following such discussions, on March 5, 2002, the Alliance RTO filed with the FERC a request for a declaratory order seeking resolution of these issues.

Coordination of East and West Zone Operating Subsidiaries

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone for all regulated subsidiaries.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

Certain Power Agreements

OVEC

AEP, CSPCo and several unaffiliated utility companies jointly own OVEC, which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 42.1%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. On September 29, 2000, DOE issued a notice of cancellation of the DOE/OVEC power agreement, such cancellation to be effective no later than April 30, 2003. In conjunction with this notice, DOE released all future rights to OVEC's generating capacity, effective September 1, 2001. DOE was therefore not entitled to any OVEC capacity beyond August 31, 2001, and the sponsoring companies became entitled to receive and pay for all OVEC capacity (approximately 2,200MW) in proportion to their power participation ratios at that time.

Buckeye

Contractual arrangements among OPCo, Buckeye and other investor-owned electric utility companies in Ohio provide for the transmission and delivery, over facilities of OPCo and of other investor-owned utility companies, of power generated by the two units at the Cardinal Station owned by Buckeye and back-up power to which Buckeye is entitled from OPCo under such contractual arrangements, to facilities owned by 25 of the rural electric cooperatives which operate in the State of Ohio at 337 delivery points. Buckeye is entitled under such arrangements to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on August 8, 2001, was recorded at 1,344,315 kilowatts.

Reference is made to *Wholesale Business Operations — Structured Arrangements Involving Capacity, Energy, and Ancillary Services* for a discussion of an agreement with an affiliate of Buckeye to construct and operate a gas-fired electric generating peaking facility.

Century Aluminum

Century Aluminum of West Virginia, Inc. (formerly Ravenswood Aluminum Corporation), operates a major aluminum reduction plant in the Ohio River Valley at Ravenswood, West Virginia. The power requirement of such plant presently is approximately 357,000 kilowatts. OPCo is providing electric service pursuant to a contract approved by the PUCO for the period July 1, 1996 through July 31, 2003.

AEGCo

Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KEPCo pursuant to unit power agreements. Pursuant to these unit power agreements, AEGCo is entitled to recover its full cost of service from the purchasers and will be entitled to recover future increases in such costs, including increases in fuel and capital costs. See *Unit Power Agreements*. Pursuant to a capital funds agreement, AEP has agreed to provide cash capital contributions, or in certain circumstances subordinated loans, to AEGCo, to the extent necessary to enable AEGCo, among other things, to provide its proportionate share of funds required to permit continuation of the commercial operation of the Rockport Plant and to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party. See *Capital Funds Agreement.*

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the date that the last of the lease terms of Unit 2 of the Rockport Plant has expired unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KEPCo unit power agreement expires on December 31, 2004. As part of AEP's restructuring settlement agreement pending with the FERC, the KEPCo unit power agreement would be extended to December 31, 2009 for Unit 1 and December 7, 2022 for Unit 2. See *Competition and Business Change—AEP Restructuring Plan.*

Capital Funds Agreement

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities, (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant, (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements), and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The Capital Funds Agreement will terminate after all AEGCo Obligations have been paid in full.

Seasonality

Sales of electricity by the AEP System tend to increase and decrease because of the use of electricity by residential and commercial customers for cooling and heating and relative changes in temperature.

Franchises

The operating companies of the AEP System hold franchises to provide electric service in various municipalities in their service areas. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

Competition and Business Change

General

The public utility subsidiaries of AEP, like many other electric utilities, have traditionally provided electric generation and energy delivery, consisting of transmission and distribution services, as a single product to their retail customers. Proposals are being made and/or legislation has been enacted in Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia and West Virginia that would also require electric utilities to sell distribution services separately. These measures generally allow competition in the generation and sale of electric power, but not in its transmission and distribution. However, movement toward retail deregulation in certain of these states is slowing as a consequence of, among other things, adverse developments related to deregulation of the electric industry in California.

Competition in the generation and sale of electric power will require resolution of complex issues, including who will pay for the unused generating plant of, and other stranded costs incurred by, the utility when a customer stops buying power from the utility; will all customers have access to the benefits of competition; how will the rules of competition be established; what will happen to conservation and other regulatory-imposed programs; how will the reliability of the transmission system be ensured; and how will the utility's obligation to serve be changed. As competition in generation and sale of electric power is instituted, the public utility subsidiaries of AEP believe that they have a favorable competitive position because of their relatively low costs. If stranded costs are not recovered from customers, however, the public utility subsidiaries of AEP, like all electric utilities, will be required by existing accounting standards to recognize any stranded investment losses.

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* and the footnote to the financial statements entitled *Customer Choice and Industry Restructuring* incorporated by reference in Items 7 and 8, respectively, for further information with respect to competition and business change.

AEP Position on Competition

AEP favors freedom for customers to purchase electric power from anyone that they choose. Generation and sale of electric power would be in the competitive marketplace. To facilitate reliable, safe and efficient service, AEP supports creation of independent system operators to operate the transmission system in a region of the United States. AEP's working model for industry restructuring envisions a progressive transition to full customer choice. Implementation of these measures would require legislative changes and regulatory approvals.

The legislatures and/or the regulatory commissions in many states, including some in AEP's service territory, are considering or have adopted "retail customer choice" which, in general terms, means the transmission by an electric utility of electric power generated by an entity of the customer's choice over its transmission and distribution system to a retail customer in such utility's service territory. A requirement to transmit directly to retail customers would have the result of permitting retail customers to purchase electric power, at the election of such customers, not only from the electric utility in whose service area they are located but from another electric utility, an independent power producer or an intermediary, such as a power marketer. Although AEP's power generation would have competitors under some of these proposals, its transmission and distribution would not. As competition develops in retail power generation, the public utility subsidiaries of AEP believe that they should have a favorable competitive position because of their relatively low costs.

Wholesale

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition to sell available power on a wholesale basis, primarily to other public utilities and also to power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market (a) through amendments to PUHCA, facilitating the ownership and operation of generating facilities by "exempt wholesale generators" (which may include independent power producers as well as affiliates of electric utilities) and (b) through amendments to the Federal Power Act, authorizing the FERC under certain conditions to order utilities which own transmission facilities to provide wholesale transmission services for other utilities and entities generating electric power. The principal factors in competing for such sales are price (including fuel costs), availability of capacity and reliability of service. The public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. However, because of the availability of capacity of other utilities and the lower fuel prices in recent years, price competition has been, and is expected for the next few years to be, particularly important.

FERC orders 888 and 889, issued in April 1996, provide that utilities must functionally unbundle their transmission services, by requiring them to use their own tariffs in making off-system and third-party sales. See *Transmission Services*. The public utility subsidiaries of AEP have functionally separated their wholesale power sales from their transmission functions, as required by orders 888 and 889.

Retail

The public utility subsidiaries of AEP have the exclusive right to sell electric power at retail within their service areas in the states of Arkansas, Indiana, Kentucky, Louisiana, Oklahoma, Tennessee and West Virginia. Furthermore, while customer choice commenced in Michigan on January 1, 2002, I&M does not have any competing suppliers active in its Michigan service territory at this time. However, AEP's public utility subsidiaries do compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to self-generation, the public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial companies in the United States, including those served by the AEP System. Such industrial companies have requested price reductions from their suppliers, including their suppliers of electric power. In addition, industrial companies which are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, various off-peak or interruptible supply options and believe that, as low cost suppliers of electric power, they should be less likely to be materially adversely affected by this competition and may be benefited by attracting new industrial customers to their service territories.

AEP Restructuring Plan

As a result of deregulating legislation that has been enacted or is being considered in several of the states in which the AEP public utility subsidiaries provide service, AEP has reassessed the corporate ownership of its public utility subsidiaries' assets. Deregulating legislation in some of the states requires the separation of generation assets from transmission and distribution assets. On November 1, 2000, AEP filed with the SEC under PUHCA for approval of a restructuring plan in part to meet the requirements of this legislation. This application is pending.

On July 24, 2001, AEP filed with the FERC for approval of the restructuring plan and on December 21, 2001, a settlement agreement with six state regulatory commissions and other major parties was filed with the FERC. The settlement agreement is pending approval. FERC approval is necessary before the SEC will issue its order.

AEP's restructuring plan is designed to align its legal structure and business activities with the requirements of deregulation. AEP's plan contemplates the formation of two first tier subsidiaries that would hold the following public utility assets:

- A subsidiary would hold the assets of public utility subsidiaries that remain subject to regulation as to rates by at least one state utility commission. AEP intends for this subsidiary ultimately to hold all transmission and distribution assets.
- A subsidiary would hold (i) public utility and non-utility subsidiaries that derive their revenues from competitive activity and (ii) foreign utility subsidiaries and other investments. AEP intends for this subsidiary to ultimately hold all generation assets not subject to regulation.

Wholesale Business Operations

AEP's wholesale business operations focus on value-driven asset optimization at each link of the energy chain through the following activities:

- A diversified portfolio of owned assets and structured third party arrangements, including:

- Power generation facilities and renewable energy sources.
- Natural gas pipeline, storage and processing facilities.
- Coal mines and related facilities.
- Barge, rail and other fuel transportation related assets.

- Trade and market energy commodities, including electric power, natural gas, natural gas liquids, oil, coal, and SO_2 allowances in North America and Europe.
- Price-risk management services and liquidity through a variety of energy-related financial instruments, including exchange-traded futures and over-the-counter forward, option, and swap agreements.
- Long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities, either existing or to be constructed, at various locations in North America and Europe.

Power Generation Facilities and Renewable Energy Sources

In addition to approximately 38,300 MW listed under Item 2. *Properties,* AEP has ownership interests in the generating facilities listed under *AEP-Other Generation* of approximately 1,900 MW domestically and 6,700 MW internationally, of which approximately 1,100 MW is from renewable energy sources.

Natural Gas Pipeline, Storage and Processing Facilities

In June 2001, AEP acquired Houston Pipe Line Company (HPL) and Lodisco LLC for $727 million from Enron Corp. The acquired assets include: (i) a 4,200-mile intrastate gas pipeline in Texas with capacity of approximately 2.4 billion cubic feet per day; (ii) the exclusive right (for 30 years with an additional 20-year extension) to the underground Bammel Storage Facility (one of the largest natural gas storage facilities in North America) with 118 billion cubic feet of storage capacity and appurtenant pipelines including the Bammel Loop, Houston City Loop and the Texas City Loop; and (iii) certain gas marketing contracts.

AEP acquired Louisiana Intrastate Gas Company, LLC ("LIG") in 1998. LIG's midstream gas assets include: (i) a 2,000-mile intrastate gas pipeline in Louisiana with capacity of approximately 800 million cubic feet per day; (ii) five natural gas processing plants that straddle the pipeline; and (iii) a ten billion cubic foot underground natural gas storage facility directly connected to the Henry Hub, one of the most active gas trading areas in North America.

Coal Mines and Related Facilities

In October 2001, to enhance its coal trading and marketing activities, AEP acquired substantially all the assets of Quaker Coal Company as part of a bankruptcy proceeding restructuring. AEP paid $101 million to Quaker's creditors and assumed additional liabilities of approximately $58 million. The acquisition included property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. AEP will continue to operate the mines and facilities which have approximately 800 employees.

Barge, Rail and Other Fuel Transportation Related Assets

In November 2001, AEP acquired MEMCO Barge Line Inc. for $270 million as part of its overall asset optimization program. MEMCO is engaged in the transportation of coal and dry bulk commodities, primarily on the Ohio, Illinois, and Lower Mississippi rivers. MEMCO owns or leases 1,200 hopper barges and 30 towboats. The addition of MEMCO's barge assets to AEP's existing fleet places AEP among the leading barge operators in the country. See *Fuel Supply—Coal and Lignite* for other barges and towboats leased by I&M and OPCo.

Trading and Marketing of Energy Commodities

Sales: Based upon volumetric sales in the U.S., *Power Markets Weekly* ranked AEP's wholesale trading business No. 2 in electric sales for the first, second and third quarters of 2001. *Platts Gas Daily* ranked AEP Nos. 14, 10 and 2 in gas sales for the first, second and third quarters, respectively, of 2001.

ICEX: To gain access to additional liquidity trading points, AEP acquired an interest in the internet-based electronic trading system, Intercontinental Exchange, L.L.C. (ICEX), in 2000 that enables participants to initiate, negotiate, and execute trades in the crude oil, natural gas, and spot and forward energy markets. Other investors include global energy companies and leading investment banking firms.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

AEP has entered into an agreement with The Dow Chemical Company to construct a 900 MW cogeneration facility at Dow's chemical facility in Plaquemine, Louisiana. Commercial operation is expected in 2003. AEP is entitled to 100% of the facility's capacity and energy and has contracted to sell the power from this facility to an unaffiliated party.

In January 2000, OPCo and National Power Cooperative, Inc. (NPC), an affiliate of Buckeye, entered into an agreement relating to construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC. From the commercial operation date (expected in 2002) until the end of 2005, OPCo will be entitled to 100% of the power generated by the facility, and responsible for the fuel and other costs of the facility. After 2005, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the facility, and both parties will generally be responsible for the fuel and other costs of the facility. OPCo will also provide certain back-up power to NPC.

International Electric

Other international holdings of AEP include the following.

Australia: CitiPower Pty. is an electric distribution and retail sales company in Victoria, Australia. CitiPower serves approximately 240,000 customers in the city of Melbourne. With about 3,100 miles of distribution lines in a service area that covers approximately 100 square miles, CitiPower distributes about 4,800 gigawatt-hours annually. AEP acquired CitiPower in 1998 for U.S.$1.1 billion.

UK: SEEBOARD, headquartered in Crawley, West Sussex and acquired as part of AEP's merger with CSW, is one of the 12 regional electricity companies formed as a result of the restructuring and subsequent privatization of the United Kingdom electricity industry in 1990. CSW acquired indirect control of SEEBOARD in April 1996. SEEBOARD's principal businesses are the distribution and supply of electricity. In addition, SEEBOARD is engaged in other businesses, including gas supply, electricity generation, and electrical contracting. SEEBOARD has approximately 2,000,000 customers and its service area covers approximately 3,000 square miles in Southeast England with the majority of its customers in Kent, Sussex and parts of Surrey.

Possible Divestitures: On February 3, 2002, AEP announced the appointment of investment banks to advise AEP on the prospects for divestment of CitiPower and/or SEEBOARD. Because of pooling of interests accounting restrictions, imposed as part of AEP's merger with CSW and which expire in June 2002, any possible divestment of CitiPower and/or SEEBOARD is not anticipated until after these restrictions lapse.

Pro Serv

Pro Serv offers engineering, construction, project management and other consulting services for projects involving transmission, distribution or generation of electric power both domestically and internationally.

AEP Communications

AEP Communications markets wholesale, high capacity, fiber optic services, colocation, and wireless tower infrastructure services under the C3 brand with operations in Arkansas, Kansas, Louisiana, Oklahoma and Texas.

AEP Communications joined with several other energy and telecommunications companies to form AFN Communications, LLC. (AFN). AFN is a super regional telecommunications company that provides long haul fiber optic capacity to competitive local exchange carriers, wireless carriers and long distance companies. AFN does business in New York, Pennsylvania, Virginia, West Virginia, Ohio, Indiana, Michigan, Illinois, and Kentucky and has approximately 10,000 route miles of fiber optic network.

C3, an entity that was acquired through the merger with CSW, is engaged in providing fiber optic and collocation services in Texas, Louisiana, Oklahoma, Arkansas, and Kansas. C3 does business as C3 Networks and has approximately 5,300 route miles of fiber optic network.

Management is evaluating certain of AEP's telecommunications investments for possible disposal.

Construction Program

General

The AEP System is continuously involved in assessing the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. Thus, System reinforcement plans are subject to change, particularly with the restructuring of the electric utility industry and the move to increasing competition in the marketplace. See *Competition and Business Change.*

Generation

Committed or anticipated capability changes to the AEP System's generation resources includes the expiration of the Rockport Unit 2 sale of 250 megawatts to Carolina Power & Light Company, an unaffiliated company, on December 31, 2009. See *AEP-CSW Merger* for a discussion of the divestiture of generating capacity as part of the merger.

Apart from these changes and temporary power purchases that can be arranged, there are no specific commitments for additions of new generation resources on the AEP System. Given the restructuring taking place in the industry, the extent of the need of AEP's operating companies for any additional generation resources in the foreseeable future is highly uncertain.

Proposed Transmission Facilities

On September 30, 1997, APCo refiled applications in Virginia and West Virginia for certificates to build a Wyoming-Cloverdale 765,000-volt Project. The preferred route for this line was approximately 132 miles in length, connecting APCo's Wyoming Station in southern West Virginia to APCo's Cloverdale Station near Roanoke, Virginia.

APCo originally announced this project in 1990. Since then it has been in the process of trying to obtain federal permits and state certificates. At the federal level, the U.S. Forest Service (Forest Service) is directing the preparation of an Environmental Impact Statement (EIS), which is required prior to granting permits for crossing lands under federal jurisdiction. Permits are needed from the (i) Forest Service to cross federal forests, (ii) Army Corps of Engineers to cross the New River and a watershed near the Wyoming Station, and (iii) National Park Service or Forest Service to cross the Appalachian National Scenic Trail.

In June 1996, the Forest Service released a Draft EIS and preliminarily identified a "No Action Alternative" as its preferred alternative for the original Wyoming-Cloverdale Project. If this alternative were incorporated into a Final EIS, APCo would not be authorized to cross federal forests administered by the Forest Service. The Forest Service stated that it would not prepare the Final EIS until after Virginia and West Virginia determined need and routing issues on non-federal lands.

West Virginia: On May 27, 1998, the West Virginia PSC issued an order granting APCo's application for a certificate to construct the Wyoming-Cloverdale 765,000-volt Project. On March 13, 2002, the West Virginia PSC issued an order granting APCo's request to construct the line with a terminus at Jacksons Ferry substation in Virginia instead of the Cloverdale substation as discussed below under *Virginia.*

Virginia: Following several procedural delays and Hearing Examiner's rulings, APCo filed a study in May 1999 identifying the Wyoming-Jacksons Ferry Project as an alternative project to the Wyoming-Cloverdale Project. The Jacksons Ferry Project proposes a line from Wyoming Station in West Virginia to APCo's existing 765,000-volt Jacksons Ferry Station in Virginia. APCo estimates that the Wyoming-Jacksons Ferry line would be 90 miles in length, including 32 miles in West Virginia previously certified. In May 2000, the Virginia SCC held an evidentiary hearing to consider both projects. On October 2, 2000, the Hearing Examiner's report to the Virginia SCC recommended approval of the Wyoming-Jacksons Ferry Alternative Project. On May 31, 2001, the Virginia SCC issued an order granting APCo's application for a certificate to construct the Wyoming-Jacksons Ferry 765,000-volt Project.

Proposed Completion Schedule and Estimated Cost: Subsequent to Virginia and West Virginia granting certificates to construct the Project, the Forest Service restarted the EIS process and is scheduled to complete and release a supplement to the Draft EIS in April 2002. The Final EIS process should continue for the balance of 2002, with a decision on the federal permits anticipated in Spring 2003. APCo has also begun required consultation with the U.S. Fish and Wildlife Service under the Endangered Species Act, which should be completed concurrently with the EIS process.

Given the status of the Project permitting process, and assuming that the projected schedule of the EIS process will be met, management estimates that the Wyoming-Jacksons Ferry 765,000-volt Project cannot be completed before Summer 2006.

Depending upon the outcome of the EIS permitting process by the Forest Service, APCo's estimated cost for the Wyoming-Jacksons Ferry Project ranges from $250 to $280 million, assuming a Summer 2006 in-service date.

Construction Expenditures

The following table shows construction expenditures during 1999, 2000 and 2001 and current estimates of 2002 construction expenditures, in each case including AFUDC but excluding assets acquired under leases.

	1999 Actual	2000 Actual	2001 Actual	2002 Estimate
	(in thousands)			
AEP System (a)	$1,679,600	$1,773,400	$1,832,000	$1,820,400
AEGCo	8,300	5,200	6,900	45,600
APCo	211,400	199,300	306,000	258,200
CPL	255,800	199,500	194,100	172,300
CSPCo	115,300	128,000	132,500	145,400
I&M	165,300	171,100	91,100	205,400
KEPCo	44,300	36,200	37,200	128,800
OPCo	193,900	254,000	344,600	349,700
PSO	104,500	176,900	124,900	80,600
SWEPCo	112,900	120,200	112,100	111,900
WTU	52,600	64,500	39,800	51,800

(a) Includes expenditures of other subsidiaries not shown.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Item 8, for further information with respect to the construction plans of AEP and its operating subsidiaries for the next three years.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

From time to time, as the System companies have encountered the industry problems described above, such companies also have encountered limitations on their ability to secure the capital necessary to finance construction expenditures.

Environmental Expenditures: Expenditures related to compliance with air and water quality standards, included in the gross additions to plant of the System, during 1999, 2000 and 2001 and the current estimate for 2002 are shown below. Substantial expenditures in addition to the amounts set forth below may be required by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted.

	1999 Actual	2000 Actual	2001 Actual	2002 Estimate
		(in thousands)		
AEGCo	$ 8	$ 70	$ 3,500	27,700
APCo	24,500	2,100	99,200	86,500
CPL	(a)	(a)	2,500	200
CSPCo	10,600	6,600	22,500	25,500
I&M	4,500	1,900	700	28,500
KEPCo	1,900	400	11,200	60,200
OPCo	37,400	91,200	125,300	103,900
PSO	(a)	(a)	400	400
SWEPCo	(a)	(a)	9,200	9,600
WTU	(a)	(a)	800	3,000
AEP System (a)	$ 78,908	$102,270	$275,300	$345,500

(a) Amounts not available for west zone companies of AEP prior to AEP-CSW merger.

Financing

It has been the practice of AEP's operating subsidiaries to finance current construction expenditures in excess of available internally generated funds by initially issuing unsecured short-term debt, principally commercial paper and bank loans, at times up to levels authorized by regulatory agencies, and then to reduce the short-term debt with the proceeds of subsequent sales by such subsidiaries of long-term debt securities and cash capital contributions by AEP. If one or more of the subsidiaries are unable to continue the issuance and sale of securities on an orderly basis, such company or companies will be required to consider the curtailment of construction and other outlays or the use of alternative financing arrangements, if available, which may be more costly.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as unsecured debt and leasing arrangements, including the leasing of utility assets and coal mining and transportation equipment and facilities. Pollution control revenue bonds have been used in the past and may be used in the future in connection with the construction of pollution control facilities; however, Federal tax law has limited the utilization of this type of financing except for purposes of certain financing of solid waste disposal facilities and of certain refunding of outstanding pollution control revenue bonds issued before August 16, 1986.

New projects undertaken by AEP's unregulated subsidiaries are generally financed through equity funds provided by AEP, non-recourse debt incurred on a project-specific basis, debt issued by such subsidiaries or through a combination thereof. See *Wholesale Business Operations* and Item 7 for additional information concerning AEP's unregulated subsidiaries.

AEP's revolving credit agreements include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2001, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event.

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* incorporated by reference in Item 7 for information with respect to AEP's plans to restructure its debt to implement corporate separation. See *Competition and Business Change—AEP Restructuring Plan* herein.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	1997	1998	1999	2000	2001
Coal	76%	79%	79%	78%	74%
Gas	12%	14%	15%	13%	12%
Nuclear	8%	3%	3%	5%	11%
Hydroelectric and other	4%	4%	3%	4%	3%

Variations in the generation of nuclear power are primarily related to refueling outages and, in 1997 through 2000, the shutdown of the Cook Plant to respond to issues raised by the NRC.

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor unrest and weather conditions which may interrupt deliveries. At December 31, 2001, the System's coal inventory was approximately 41 days of normal System usage. This estimate assumes that the total supply would be utilized by increasing or decreasing generation at particular plants.

The following tabulation shows the total consumption during 2001 of the coal-fired generating units of AEP's principal electric utility subsidiaries, coal requirements of these units over the remainder of their useful lives and the average sulfur content of coal delivered in 2001 to these units. Reference is made to *Environmental and Other Matters* for information concerning current emissions limitations in the AEP System's various jurisdictions and the effects of the Clean Air Act Amendments.

	Total Consumption During 2001 (In Thousands of Tons)	Estimated Requirements for Remainder of Useful Lives (In Millions of Tons)	Average Sulfur Content of Delivered Coal	
			By Weight	Pounds of SO_2 Per Million Btu's
AEGCo (a)	4,829	215	0.3%	0.7
APCo	10,529	375	0.7%	1.2
CPL	2,470	36	0.3%	0.7
CSPCo	5,637	213(b)	2.4%	4.1
I&M (c)	7,026	244	0.6%	1.2
KEPCo	2,981	80	0.9%	1.5
OPCo	19,392	546(d)	2.1%	3.5
PSO	4,049	41	0.4%	0.9
SWEPCo	12,254	117	0.6%	1.6
WTU	1,370	32	0.4%	0.8

(a) Reflects AEGCo's 50% interest in the Rockport Plant.
(b) Includes coal requirements for CSPCo's interest in Beckjord, Stuart and Zimmer Plants.
(c) Includes I&M's 50% interest in the Rockport Plant.
(d) Total does not include OPCo's portion of Sporn Plant.

AEGCo: See *Fuel Supply — I&M* for a discussion of the coal supply for the Rockport Plant.

APCo: Substantially all of the coal consumed at APCo's generating plants is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

The average sulfur content by weight of the coal received by APCo at its generating stations approximated 0.7% during 2001, whereas the maximum sulfur content permitted, for emission standard purposes, for existing plants in the regions in which APCo's generating stations are located ranged between 0.78% and 2% by weight depending in some circumstances on the calorific value of the coal which can be obtained for some generating stations.

CPL: CPL has coal supply agreements of one year or less duration with two coal suppliers and various coal trading firms for the delivery of approximately 2,400,000 tons of coal for the year 2002. Approximately one half of the coal delivered to Coleto Creek is from Wyoming with the other half from Colorado. Both sources supply low sulfur coal with a limit of 1.2 lbs/MMBtu.

CSPCo: CSPCo has coal supply agreements with unaffiliated suppliers for the delivery of approximately 3,780,000 tons in 2002. Some of this coal is washed to improve its quality and consistency for use principally at Unit 4 of the Conesville Plant.

CSPCo has been informed by CG&E and DP&L that, with respect to the CCD Group units partly owned but not operated by CSPCo, sufficient coal has been contracted for or is believed to be available for the approximate lives of the respective units operated by them. Under the terms of the operating agreements with respect to CCD Group units, each operating company is contractually responsible for obtaining the needed fuel.

I&M: I&M has historically received coal under two coal supply agreements with unaffiliated Wyoming suppliers for low sulfur coal from surface mines principally for consumption at the Rockport Plant. As a result of litigation involving future deliveries from one of these suppliers, there will not be any coal delivered under this contract in 2002. Under the other agreement, the supplier will sell to I&M, for consumption by I&M at the Rockport Plant or consignment to other System companies, coal with an average sulfur content not exceeding 1.2 pounds of sulfur dioxide per million Btu's of heat input. This contract, which expires on December 31, 2004, has remaining deliveries of approximately 22,800,000 tons.

All of the coal consumed at I&M's Tanners Creek Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

KEPCo: Substantially all of the coal consumed at KEPCo's Big Sandy Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis. KEPCo has coal supply agreements with unaffiliated suppliers pursuant to which KEPCo will receive approximately 648,000 tons of coal in 2002. To the extent that KEPCo has additional coal requirements, it may purchase coal from the spot market and/or suppliers under contract to supply other System companies.

OPCo: The coal consumed at OPCo's generating plants has historically been supplied from both affiliated and unaffiliated suppliers. As a result of the 2001 sale of AEP's coal mines in Ohio and West Virginia and an agreement to purchase approximately 34,000,000 tons of coal through 2008 from the purchaser of the mines, coal consumed at OPCo's plants in 2002 will be supplied from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

PSO: PSO takes all its coal from one coal supplier under a contract that provides for the entire plant requirements with at least 16,830,000 tons remaining to be delivered between 2002 and 2007. The coal is supplied from Wyoming and has a maximum sulfur content of 1.2 lbs. SO_2 per MMBtu.

SWEPCo: SWEPCo receives coal at its plants under a combination of agreements, including one long-term coal contract with a Wyoming producer, one affiliate mine-mouth lignite operation and agreements with various producers and coal trading firms. SWEPCo's long-term coal supply contract provides approximately half of the requirements for both coal plants. SWEPCo must take delivery of 25,625,000 tons of coal through 2006, with the remainder of its coal requirements met through short-term spot agreements for low sulfur (less than 1.2 lbs. SO_2 per MMBtu) coal with various Wyoming coal suppliers and trading companies.

WTU: WTU has one long-term coal supply contract that provides approximately two-thirds of the coal requirements for the Oklaunion Power Station. This contract has approximately 9,180,000 tons of coal remaining to be delivered between 2002 and mid-2006. The remaining coal requirements for Oklaunion are being purchased under short-term agreements with various Wyoming coal suppliers and coal trading firms, with such coal being low sulfur (less than 1.2 lbs. SO_2 per MMBtu).

Nuclear

I&M and STPNOC have made commitments to meet certain of the nuclear fuel requirements of the Cook Plant and STP, respectively. The nuclear fuel cycle consists of:

- Mining and milling of uranium ore to uranium concentrates.
- Conversion of uranium concentrates to uranium hexafluoride.
- Enrichment of uranium hexafluoride.
- Fabrication of fuel assemblies.
- Utilization of nuclear fuel in the reactor.
- Disposition of spent fuel.

Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review and evaluate I&M's requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted.

CPL and the other STP participants have entered into contracts with suppliers for 100% of the uranium concentrate sufficient for the operation of both STP units through Spring 2006 and with an additional 50% of the uranium concentrate needed for STP through Spring 2007. In addition, CPL and the other STP participants have entered into contracts with suppliers for 100% of the nuclear fuel conversion service sufficient for the operation of both STP units through Spring 2003, with additional flexible contracts to provide at least 50% of the conversion service needed for STP through 2008. CPL and the other STP participants have entered into flexible contracts to provide for 100% of enrichment through Fall 2004, with additional flexible contracts to provide at least 50% of enrichment services through Fall 2008. Also, fuel fabrication services have been contracted for operation through 2028 for Unit 1 and 2029 for Unit 2.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M has completed modifications to its spent nuclear fuel storage pool. AEP anticipates that the Cook Plant has storage capacity to permit normal operations through 2012.

STP has on-site storage facilities with the capability to store the spent nuclear fuel generated by the STP units over their licensed lives.

The costs of nuclear fuel consumed by I&M and CPL do not assume any residual or salvage value for residual plutonium and uranium.

Nuclear Waste and Decommissioning

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the financial statements and *Commitments and Contingencies* in the footnotes to these statements that are incorporated by reference in Items 7 and 8, respectively, for information with respect to nuclear waste and decommissioning and related litigation.

The ultimate cost of retiring the Cook Plant and STP may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected.
- Escalation of various cost elements (including, but not limited to, general inflation).
- Further development of regulatory requirements governing decommissioning.
- Limited availability to date of significant experience in decommissioning such facilities.
- Technology available at the time of decommissioning differing significantly from that assumed in these studies.
- Availability of nuclear waste disposal facilities.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant and STP will not be significantly greater than current projections.

Low-Level Waste: The Low-Level Waste Policy Act of 1980 (LLWPA) mandates that the responsibility for the disposal of low-level waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. To facilitate this approach, the LLWPA authorized states to enter into regional compacts for low-level waste disposal subject to Congressional approval. The LLWPA also specified that, beginning in 1986, approved compacts may prohibit the importation of low-level waste from other regions, thereby providing a strong incentive for states to enter into compacts. Michigan, the state where the Cook Plant is located, was a member of the Midwest Compact, but its membership was revoked in 1991. As a result, Michigan is responsible for developing a disposal site for the low-level waste generated in Michigan.

Although Michigan amended its law regarding low-level waste site development in 1994 to allow a volunteer to host a facility, little progress has been made to date. A bill was introduced in 1996 to further address the issue but no action was taken. Development of required legislation and progress with the site selection process has been inhibited by many factors, and management is unable to predict when a new disposal site for Michigan low-level waste will be available.

Texas is a member of the Texas Compact, which includes the states of Maine and Vermont. Texas had identified a disposal site in Hudspeth County for construction of a low-level waste disposal facility. During the licensing process for the Hudspeth site, that site was found to be unsuitable. No additional site has been considered. Management is unable to predict when a disposal site for Texas low-level waste will be available.

On July 1, 1995, the disposal site in South Carolina reopened to accept waste from most areas of the U.S., including Michigan and Texas. This was the first opportunity for the Cook Plant to dispose of low-level waste since 1990. To the extent practicable, the waste formerly placed in storage and the waste presently generated by the Cook Plant and STP are now being sent to the disposal site.

Under state law, the amounts of low-level radioactive waste being disposed of at the South Carolina facility from non-regional generators, such as the Cook Plant and STP, are limited and being reduced. Non-regional access to the South Carolina facility is currently allowed through the end of fiscal year 2008.

Environmental and Other Matters

AEP's subsidiaries are subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions.

It is expected that:

- Costs related to environmental requirements will eventually be reflected in the rates of AEP's electric utility subsidiaries, or where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.
- AEP's electric utility subsidiaries will be able to provide for required environmental controls.

However, some customers may curtail or cease operations as a consequence of higher energy costs. There can be no assurance that all such costs will be recovered. Moreover, legislation adopted by certain states and proposed at the state and federal level governing restructuring of the electric utility industry may also affect the recovery of certain costs. *See Competition and Business Change.*

Except as noted herein, AEP's subsidiaries that own or operate generating, transmission and distribution facilities are in substantial compliance with pollution control laws and regulations.

AEP's international operations are subject to regulation with respect to air, waste and water quality standards and other environmental matters by various authorities within the host countries. Under certain circumstances, these authorities may require modifications to these facilities and operations or impose fines and other costs for violations of applicable statutes and regulations. From time to time, these operations are made aware of various environmental issues or are named as parties to various legal claims, actions, complaints or other proceedings related to environmental matters. Management does not expect disposition of any such pending environmental proceedings to have a material adverse effect on AEP's consolidated results of operations or financial condition.

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* and the footnote to the financial statements entitled

Commitments and Contingencies incorporated by reference in Items 7 and 8, respectively, for further information with respect to environmental matters, including discussion of legislative proposals under consideration by the Administration and Congress focused on reductions in emissions of CO_2, NO_x, SO_2, mercury and other constituents.

Air Pollution Control

For the AEP System operating companies, compliance with the CAA is requiring substantial expenditures that generally are being recovered through the rates of AEP's operating subsidiaries. Certain matters discussed below may require significant additional operating and capital expenditures. However, there can be no assurance that all such costs will be recovered. *See Construction Program — Construction Expenditures.*

Title I National Ambient Air Quality Standards Attainment: In July 1997, Federal EPA revised the ozone and particulate matter National Ambient Air Quality Standards (NAAQS), creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). In addition to the potential financial consequences discussed above, both of these new standards have the potential to affect adversely the operation of AEP System generating units. In May 1999, the U.S. Court of Appeals for the District of Columbia Circuit remanded the ozone and $PM_{2.5}$ NAAQS to Federal EPA. In February 2001, the U.S. Supreme Court issued an opinion reversing in part and affirming in part the Court of Appeals decision. The Supreme Court remanded the case to the Court of Appeals for further proceedings, including a review of whether adoption of the standards was arbitrary and capricious and directed Federal EPA to develop a policy for implementing the revised ozone standard in conformity with the CAA. The Court of Appeals held oral argument on the remanded issues in December 2001.

NO_x SIP Call: In October 1998, Federal EPA issued a final rule (NO_x transport SIP call or NO_x SIP Call) establishing state-by-state NO_x emission budgets for the five-month ozone season to be met beginning May 1, 2003. The NO_x budgets originally applied to 22 eastern states and the District of Columbia and are premised mainly on the assumption of controlling power plant NO_x emissions projected for the year 2007 to 0.15 lb. per million Btu (approximately 85% below 1990 levels), although the reductions could be substantially greater for certain State Implementation Plans. The SIP call was accompanied by a proposed Federal Implementation Plan, which could be implemented in any state that fails to submit an approvable SIP. The NO_x reductions called for by Federal EPA are targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to construct new facilities or to operate affected facilities without making significant capital expenditures.

In October 1998, the AEP System operating companies joined with certain other parties seeking a review of the final NO_x SIP Call rule in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2000, the court issued a decision upholding the major provisions of the rule. The court subsequently extended the date for submission of SIP revisions until October 30, 2000, and the compliance deadline until May 31, 2004. In March 2001, the U.S. Supreme Court denied petitions filed by industry petitioners, including AEP System operating companies, seeking review of the Court of Appeals decision.

In May 1999 and March 2000, Federal EPA finalized the NO_x budget allocations to be implemented through the NO_x SIP Call. AEP and other parties filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit and in June 2000 the court issued an opinion remanding the budget determinations for further consideration of certain growth factor assumptions made by Federal EPA. In December 2000, Federal EPA issued a determination that eleven states, including certain states in which AEP System operating companies have sources covered by the NO_x SIP Call rule, had failed to submit complying SIP revisions. AEP System operating companies and unaffiliated utilities appealed this determination to the U.S. Court of Appeals for the District of Columbia Circuit and the court has stayed the proceeding pending Federal EPA action on the remand of growth factor issues.

In April 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NO_x emissions from utility sources, including those of CPL and SWEPCo. The rule compliance date is May 2003 for CPL and May 2005 for SWEPCo.

Management's estimates indicate that compliance with the revised NO_x SIP Call rule, and SIP revisions already adopted, could result in required capital expenditures for the AEP System of approximately $1.6 billion, of which approximately $450 million has been expended through December 31, 2001. Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Item 8 for information with respect to AEP registrant subsidiaries' compliance cost estimates and amounts expended.

In May 2001, OPCo completed a $175 million installation of selective catalytic reduction (SCR) technology to reduce NO_x emissions on its two-unit 2,600 MW Gavin Plant and, during the 2001 ozone season (May through September), operated the SCR units. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and on APCo's Mountaineer Plant, began in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million. Management has undertaken the Gavin, Amos and Mountaineer projects to meet applicable NO_x emission reduction requirements. Additional expenditures of approximately $7 million are planned or undertaken to address certain operational issues arising during initial operation of the Gavin SCR units.

Since compliance costs cannot be estimated with certainty, the actual costs to comply could be significantly different from management's estimates depending upon the compliance alternatives selected to achieve reductions in NO_x emissions. Unless capital and operating costs of any additional pollution control equipment necessary for compliance are recovered from customers through regulated rates and market prices for electricity, they could have a material adverse effect on future results of operations, cash flows and possibly financial condition of AEP and its affected subsidiaries.

Section 126 Petitions: In January 2000, Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the CAA. The petitions sought significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposed emission reduction requirements comparable to the NO_x SIP Call rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP System operating companies and other utilities filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit. In May 2001, the court issued an opinion which upheld substantially the entire rule. The court did not agree that Federal EPA had properly supported the growth factors for the NO_x allowance budgets. In August 2001, the court issued an order tolling the May 1, 2003, compliance date pending resolution of the remand of the growth factor issues. In January 2002, Federal EPA advised that it intends to establish May 31, 2004, as the final compliance date for the rule. Cost estimates for compliance with Section 126 are projected to be somewhat less than those set forth above for the NO_x SIP Call rule reflecting the fact that Section 126 does not apply to AEGCo's and I&M's Rockport Plant.

West Virginia SO_2 Limits: West Virginia promulgated SO_2 limitations, which Federal EPA approved in February 1978. The emission limitations for OPCo's Mitchell Plant have been approved by Federal EPA for primary ambient air quality (health-related) standards only. West Virginia is obligated to reanalyze SO_2 emission limits for the Mitchell Plant with respect to secondary ambient air quality (welfare-related) standards. Because the CAA provides no specific deadline for approval of emission limits to achieve secondary ambient air quality standards, it is not certain when Federal EPA will take dispositive action regarding the Mitchell Plant.

In August 1994, Federal EPA issued a Notice of Violation to OPCo alleging that Kammer Plant was operating in violation of the applicable federally enforceable SO_2 emission limit. In May 1996, the Notice of Violation and an enforcement action subsequently filed by Federal EPA were resolved through the entry of a consent decree in the

U.S. District Court for the Northern District of West Virginia. Kammer Plant has achieved and maintained compliance with the applicable SO_2 emission limit for a period in excess of one year, pursuant to the provisions of the consent decree. In May 2001, the court terminated the consent decree.

Short Term SO_2 Limits: In January 1997, Federal EPA proposed a new intervention level program under the authority of Section 303 of the CAA to address five-minute peak SO_2 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 SO_2 levels. In January 2001, Federal EPA published a *Federal Register* notice inviting comment with respect to its decision not to promulgate a five-minute SO_2 NAAQS and intent to take final action on the intervention level program by the summer of 2001. The effect of this proposed intervention program on AEP operations or financial performance cannot be predicted at this time.

Hazardous Air Pollutants: Hazardous air pollutant (HAP) emissions from utility boilers are potentially subject to control requirements under Title III of the CAAA which specifically directed Federal EPA to study potential public health impacts of HAPs emitted from electric utility steam generating units. In December 2000, Federal EPA announced its intent to regulate emissions of mercury from coal and oil-fired power plants, concluding that these emissions pose significant hazards to public health. A decision on whether to regulate other HAPs emissions from these sources was deferred.

Federal EPA added coal and oil-fired electric utility steam generating units to the list of "major sources" of HAPs under Section 112 (c) of the CAA, which compels the development of "Maximum Achievable Control Technology" (MACT) standards for these units. Listing under Section 112 (c) also compels a preconstruction permitting obligation to establish case-by-case MACT standards for each new or reconstructed source in the category. MACT standards for utility mercury emissions are scheduled to be proposed by December 2003 and finalized by December 2004. The Utility Air Regulatory Group (which includes AEP System operating companies as members) filed a petition with Federal EPA seeking reconsideration of the decision to regulate mercury emissions from power plants under Section 112(c) of the CAA.

In addition, Federal EPA is required to study the deposition of hazardous pollutants in the Great Lakes, the Chesapeake Bay, Lake Champlain, and other coastal waters. As part of this assessment, Federal EPA is authorized to adopt regulations to prevent serious adverse effects to public health and serious or widespread environmental effects. In 1998, Federal EPA determined that the CAA is adequate to address any adverse public health or environmental effects associated with the atmospheric deposition of hazardous air pollutants in the Great Lakes. The potential impact of adverse developments in these programs on AEP operations or financial performance cannot be predicted at this time.

Title IV Acid Rain Program: The Acid Rain Program (Title IV) of the CAAA created an emission allowance program pursuant to which utilities are authorized to emit a designated quantity of SO_2, measured in tons per year.

Phase II of the Acid Rain Program, which affects all fossil fuel-fired steam generating units with capacity greater than 25 megawatts imposed 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 Phase II allowance allocation is premised upon an emission rate of 1.2 pounds at 1985 utilization levels. Future SO_2 requirements will be met through accumulation or acquisition of allowances, the use of controls or fuels, or a combination thereof. See *Fuel Supply—Coal and Lignite*.

Title IV of the CAAA also regulates emissions of NO_x. Federal EPA has promulgated NO_x emission limitations for all boiler types in the AEP System at levels significantly below original design, which were to be achieved by January 1, 2000 on a unit-by-unit or System-wide average basis. AEP sources subject to Title IV of the CAAA are in compliance with the provisions thereof.

Regional Haze: In July 1999, Federal EPA finalized 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, the rules address the potential regulation of such precursor emissions in every state. Under the rule, 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. In addition, Federal EPA intends to require Best Available Retrofit Technology (BART) for power plants and other large emission sources constructed between 1962 and 1977.

In January 2001, Federal EPA proposed guidelines for states to use in setting BART emission limits for power plants and other large emission sources and in determining which sources are subject to those limits. The proposed rule calls for technologies which Federal EPA estimates are capable of reducing SO_2 emissions by 90 to 95 percent. The proposed rule also contemplates that other visibility-impairing emissions must be reduced. Emission trading programs could be used in lieu of unit-by-unit BART requirements under the proposal, provided they yield greater visibility improvement and emission reductions.

The AEP System is a significant emitter of fine particulate matter and other precursors of regional haze and a number of AEP's generating units could be subject to BART controls. Federal EPA's regional haze rule may have an adverse financial impact on AEP as it may trigger the requirement to install costly new pollution control devices to control emissions of fine particulate matter and its precursors (including SO_2 and NO_x). The actual impact of the regional haze regulations cannot be determined at this time. AEP System operating companies and other utilities filed a petition seeking a review of the regional haze rule in the U.S. Court of Appeals for the District of Columbia Circuit in August 1999.

Permitting and Enforcement: 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.
- Imposing a national operating permit system, emission fee program and enhanced monitoring, recordkeeping and reporting requirements.

Section 103 of CERCLA and Section 304 of the Emergency Planning and Community Right-to-Know Act require notification to state and federal authorities of releases of reportable quantities (RQs) of hazardous and extremely hazardous substances. A number of these substances are emitted by AEP's power plants and other sources. Until recently, emissions of these substances, whether expressly limited in a permit or otherwise subject to federal review or waiver (*e.g.*, mercury), were deemed "federally permitted releases" which did not require emergency notification. In December 1999, Federal EPA published interim guidance in the *Federal Register*, which provided that any hazardous substance or extremely hazardous substance not expressly and individually limited in a permit must be reported if they are emitted at levels above an RQ. Specifically, constituents of regulated pollutants (*e.g.*, metals contained in particulate matter) were not deemed to be federally permitted. AEP System operating companies have provided supplemental information regarding air releases from their facilities and are submitting follow-up reports. Federal EPA suspended its December 1999 guidance as it considers certain revisions to the guidance. Settlement discussions regarding the guidance are underway.

Global Climate Change: In December 1997, delegates from 167 nations, including the U.S., agreed to a treaty, known as the "Kyoto Protocol," establishing legally-binding emission reductions for gases suspected of causing climate change. The Protocol requires ratification by at least 55 nations that account for at least 55% of developed countries' 1990 emissions of CO_2 to enter into force.

Although the U.S. signed the treaty on November 12, 1998, it was not sent to the Senate for its advice and consent to ratification. In a letter dated March 13, 2001 from President Bush to four U. S. senators, he indicated his opposition to the Kyoto Protocol and said he does not believe that the government should impose mandatory emissions reductions for CO_2 on the electric utility sector.

Despite U.S. opposition to the treaty, at the Seventh Conference of the Parties to the United Nations Framework Convention on Climate Change, held in Marrakech, Morocco in November 2001, the parties finalized the rules, procedures and guidelines required to facilitate ratification of the treaty by most nations, and entry into force is expected by 2003.

Since the AEP System is a significant emitter of carbon dioxide, its results of operations, cash flows and financial condition could be materially adversely affected by the imposition of limitations on CO_2 emissions if compliance costs cannot be fully recovered from customers. In addition, any program to reduce CO_2 emissions could impose substantial costs on industry and society and erode the economic base that AEP's operations serve. However, it is management's belief that the Kyoto Protocol is highly unlikely to be ratified or implemented in the U.S. in its current form. AEP's 4,000 MW of coal-fired generation in the United Kingdom acquired in 2001 may be exposed to potential carbon dioxide emission control obligations since the U.K. is expected to be a party to the Kyoto Protocol. AEP is developing an emissions mitigation plan for these plants to ensure compliance as necessary.

On February 14, 2002, President Bush announced new climate change initiatives for the U.S. Among the policies to be pursued is a voluntary commitment to reduce the "greenhouse gas intensity" of the economy by 18% within the next ten years. It is anticipated that the Administration will seek to partner with various industrial sectors, including the electric utility industry, to reach this goal. AEP is unable to predict at this time the effect that this program will have upon its operations or financial performance in the future.

New Source Review: In July 1992, Federal EPA published final regulations governing application of new source rules to generating plant repairs and pollution control projects undertaken to comply with the CAA. Generally, the rule provides that plants undertaking pollution control projects will not trigger New Source Review (NSR) requirements. The Natural Resources Defense Council and a group of utilities, including five AEP System operating companies, filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the regulations. In July 1998, Federal EPA requested comment on proposed revisions to the New Source Review rules, which would change New Source Review applicability criteria by eliminating exclusions contained in the current regulation. The Administration and Congress are considering initiatives to reform the NSR requirements, but no regulatory revisions have been proposed to date.

New Source Review Litigation: On November 3, 1999, following issuance by Federal EPA of substantial information requests to AEP System operating companies, the Department of Justice (DOJ), on Federal EPA's behalf, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges AEP made modifications to generating units at certain of its coal-fired generating plants over the course of the past 20 years that extend unit operating lives or restore or increase unit generating capacity without a preconstruction permit in violation of the CAA. The complaint named OPCo's Cardinal Unit 1, Mitchell, Muskingum River, and Sporn plants and I&M's Tanners Creek plant. Federal EPA also issued Notices of Violation to AEP alleging similar violations at certain other AEP plants.

In March 2000, DOJ filed an amended complaint that added allegations for certain of the AEP plants previously named in the complaint as well as counts for APCo's Amos, Clinch River, and Kanawha River plants, CSPCo's Conesville Plant, and OPCo's Kammer Plant. In addition to the allegations regarding New Source Review and New Source Performance Standard violations, DOJ included allegations regarding visible particulate emission violations for Cardinal and Muskingum River plants.

A number of northeastern and eastern states, have been allowed to intervene in the litigation, and a number of special interest groups filed a separate complaint based on substantially similar allegations, which has been consolidated with the DOJ complaint. In addition to the plants named by the government and special interest groups, the intervenor states have included allegations concerning OPCo's Gavin Plant.

In May 2000, AEP filed a motion to dismiss with the District Court, which, if granted, would dispose of most of the claims of the government and intervenors.

In February 2001, the plaintiffs filed a motion for partial summary judgment seeking a determination that four projects undertaken on units at Sporn, Cardinal, and Clinch River Plants do not constitute "routine maintenance, repair and replacement" as used in the NSR programs. In August 2001, the court issued an order denying the plaintiffs' motion as premature. Management believes its maintenance, repair and replacement activities were in conformity with the CAA and intends to vigorously pursue its defense.

A number of unaffiliated utilities have also received notices of violation, complaints, or administrative orders relating to NSR. A notice of violation was issued in June 2000 to DP&L with respect to its ownership interest in Stuart Station, in which CSPCo also owns a 26 percent interest. W.C. Beckjord Unit 6, operated by CG&E, in which CSPCo owns a 12.5 percent interest, is also the subject of an enforcement action. Cinergy Corp., the parent company of CG&E, has entered into an agreement in principle with the DOJ in an attempt to resolve the litigation relating to W.C. Beckjord Unit 6 and other plants owned or operated by Cinergy and its subsidiaries. This agreement in principle also covers the Zimmer Plant which has not been the subject of an enforcement action. VEPCo has also entered into a similar agreement in principle. Neither CG&E nor VEPCo have reached final agreements with the DOJ. Two other unaffiliated utilities, Tampa Electric Company and PSEG Fossil, LLC, have reached settlements with the Federal government.

In November 2000, several environmental groups filed a petition with Ohio EPA seeking to have the draft Title V operating permits for OPCo's Cardinal and Muskingum River plants as well as the Beckjord Plant and a plant owned by an unaffiliated utility, modified to incorporate requirements and timetables for compliance with New Source Review requirements. In December 2000, a petition was filed by these groups with the Administrator of Federal EPA seeking a similar modification of the final Title V permit for CSPCo's Conesville Plant. Ohio EPA has refused to consider these petitions outside the regular Title V permit processing procedures or to interfere with the resolution of these issues by the District Court.

The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In March 2001, the District Court issued orders holding that claims for civil penalties based on alleged activities that occurred more than five years prior to the filing of the complaint are barred. Although the plaintiffs' claims for injunctive relief are not barred, the court noted that the nature of the relief ordered may be impacted by the plaintiffs' delay in filing the complaints.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings and unable to predict the timing of resolution of these matters due to the number of alleged violations and issues to be determined by the court. In the event the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed could materially adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Water Pollution Control

The Clean Water Act prohibits the discharge of pollutants to waters of the United States from point sources except pursuant to an NPDES permit issued by Federal EPA or a state under a federally authorized state program.

Under the Clean Water Act, effluent limitations requiring application of the best available technology economically achievable are to be applied, and those limitations require that no pollutants be discharged if Federal EPA finds elimination of such discharges is technologically and economically achievable.

The Clean Water Act provides citizens with a cause of action to enforce compliance with its pollution control requirements. Since 1982, many such actions against NPDES permit holders have been filed. To date, no AEP System plants have been named in such actions.

All AEP System generating plants are required to have NPDES permits and have received them. NPDES permit conditions and effluent limitations are reviewed during the permit renewal process. Under Federal EPA's regulations, operation under an expired NPDES permit is authorized provided an application is filed at least 180 days prior to expiration. Renewal applications are being prepared or have been filed for renewal of NPDES permits that expire in 2002.

The NPDES permits generally require that certain thermal impact study programs be undertaken. These studies have been completed for all System plants. Thermal variances are in effect for all plants with once-through cooling water. The thermal variances for CSPCo's Conesville and OPCo's Muskingum River plants impose thermal management conditions that could result in load curtailment under certain conditions, but the cost impacts are not expected to be significant. Based on favorable results of in-stream biological studies, the thermal limits for both Conesville and Muskingum River plants were raised in the renewed permits issued in 1996. Consequently, the potential for load curtailment and adverse cost impacts was further reduced. In early 2002, AEP submitted a petition to Ohio EPA requesting additional less stringent thermal loading limitations for these plants.

Section 316(b) of the Clean Water Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Federal EPA issued final regulations defining BTA for new sources that were published in the *Federal Register* on December 18, 2001. New sources are those commencing construction after January 17, 2002. On February 28, 2002, Federal EPA issued a proposed rule addressing BTA for intake structures at existing plants. This proposal is expected to be published in the *Federal Register* for comment in April 2002. Under a previous court-established schedule, Federal EPA is required to issue final regulations for existing plants by August 2003. Federal EPA's rulemaking could result in a definition of BTA that could ultimately require retrofitting of certain existing plant intake structures. Such changes would involve costs for AEP System operating companies, but the significance of these costs cannot be determined at this time.

Certain mining operations conducted by System companies as discussed under *Fuel Supply* are also subject to federal and state water pollution control requirements, which may entail substantial expenditures for control facilities, not included at present in the System's construction cost estimates set forth herein.

Section 303 of the Federal Clean Water Act requires states to adopt stringent water quality standards for a large category of toxic pollutants and to identify specialized control measures for dischargers to waters where it is shown that water quality standards are not being met. In order to bring these waters back into compliance, total maximum daily load (TMDL) allocations of these pollutants will be made, and subsequently translated into discharge limits in NPDES permits. Federal EPA has also directed that states take action to adopt enhanced anti-degradation of water quality requirements. In October 2001, Federal EPA issued a rule delaying until April 30, 2003, the effective date of its TMDL rule issued in July 2000, the effective date of which had been previously delayed by Congress. Implementation of these provisions could result in significant costs to the AEP System if biological monitoring requirements and water quality-based effluent limits and requirements are placed in NPDES permits.

In March 1995, Federal EPA finalized a set of rules that establish minimum water quality standards, anti-degradation policies and implementation procedures for more stringently controlling releases of toxic pollutants into the Great Lakes system. This regulatory package is called the Great Lakes Water Quality Initiative (GLWQI). The most direct compliance cost impact could be related to I&M's Cook Plant. Based on Federal EPA's current policy on intake credits and site specific variables and Michigan's implementation strategy, management does not presently expect the GLWQI will have a significant adverse impact on Cook Plant operations. If Indiana and Ohio eventually adopt the GLWQI criteria for statewide application, AEP System plants located in those states could be adversely affected, although the significance depends on the implementation strategy of those states.

Oil Pollution Act: The Oil Pollution Act of 1990 (OPA) defines certain facilities that, due to oil storage volume, and location, could reasonably be expected to cause significant and substantial harm to the environment by discharging oil. Such facilities must operate under approved spill response plans and implement spill response training and drill programs. OPA imposes substantial penalties for failure to comply. AEP System operating companies with oil handling and storage facilities meeting the OPA criteria have in place required response plans, training and drill programs.

Solid and Hazardous Waste

Section 311 of the Clean Water Act imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. CERCLA expanded the reporting requirement to cover the release of hazardous substances generally into the environment, including water, land and air. AEP's subsidiaries store and use some of these hazardous substances, including PCBs contained in certain capacitors and transformers, but the occurrence and ramifications of a spill or release of such substances cannot be predicted.

CERCLA, RCRA and similar state laws provide governmental agencies with the authority to require cleanup 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, joint and several, and can be applied retroactively, AEP System operating 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.

AEP System operating companies are identified as Potentially Responsible Parties (PRPs) for five federal sites where remediation has not been completed, including APCo at one site, CSPCo at one site, I&M at two sites, and OPCo at one site. AEP has also been named a PRP at two sites under state law. Management's present estimates do not anticipate material clean-up costs for identified sites for which AEP subsidiaries have been declared PRPs. In addition, AEP subsidiary companies are engaged in certain remedial projects at various locations, the costs of which are not expected to be material. However, if significant costs are incurred for cleanup, future results of operations and possibly financial condition could be adversely affected unless the costs can be recovered through rates and/or future market prices for electricity where generation is deregulated.

Regulations issued by Federal EPA under the Toxic Substances Control Act govern the use, distribution and disposal of PCBs, including PCBs in electrical equipment. Deadlines for removing certain PCB-containing electrical equipment from service have been met.

In addition to handling hazardous substances, the System companies generate solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and flue gas desulfurization wastes. These wastes presently are considered to be non-hazardous under RCRA and applicable state law and the wastes are treated and disposed of in surface impoundments or landfills in accordance with state permits or authorization or are beneficially utilized. As required by RCRA, Federal EPA evaluated whether high volume coal combustion wastes (such as fly ash, bottom ash and flue gas desulfurization wastes) should be regulated as hazardous waste. In August 1993, Federal EPA issued a regulatory determination that such high volume coal combustion wastes should not be regulated as hazardous waste. Federal EPA chose to address separately the issue of low volume wastes (such as metal and boiler cleaning wastes) associated with burning coal and other fossil fuels. In May 2000, Federal EPA issued a regulatory determination that such low volume wastes are also excluded from regulation under the RCRA hazardous waste provisions when mixed and co-managed with high volume fossil fuel combustion wastes.

All presently generated hazardous waste is being disposed of at permitted off-site facilities in compliance with applicable federal and state laws and regulations. For System facilities that generate such wastes, System companies have filed the requisite notices and are complying with RCRA and applicable state regulations for generators. Nuclear waste produced at the Cook Plant and STP and regulated under the Atomic Energy Act is excluded from regulation under RCRA.

Underground Storage Tanks: Federal EPA's technical requirements for underground storage tanks containing petroleum required retrofitting or replacement of an appreciable number of tanks. Compliance costs for tank replacement were not significant. Some limited site remediation associated with tank removal is ongoing, but these costs are not expected to be significant.

Electric and Magnetic Fields (EMF)

EMF is found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF is created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, the majority of studies have indicated no such association.

The Energy Policy Act of 1992 established a coordinated Federal EMF research program which ended in 1998. In 1999, the National Institute of Environmental Health Sciences (NIEHS), as required by the Act, provided a report to Congress summarizing the results of this program. The report concluded that "the probability that ...EMF is truly a health hazard is currently small" and that the evidence that exists for health effects is "insufficient to warrant aggressive regulatory actions." Nevertheless, the NIEHS identified several areas where further research might be warranted. AEP has supported EMF research through the years and continues to fund the Electric Power Research Institute's EMF research program, contributing over $400,000 to this program in 2001, and intending to contribute a similar amount in 2002. See *Research and Development.*

AEP's participation in these programs is a continuation of its efforts to monitor and support further research and to communicate with its customers and employees about this issue. Residential customers of AEP are provided information and field measurements on request, although there is no scientific basis for interpreting such measurements.

Some states have enacted regulations to limit the strength of magnetic fields at the edge of transmission line rights-of-way. No state which the AEP System serves has done so.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from ratepayers.

Research and Development

AEP and its subsidiaries are involved in over 100 research projects that focus on:

- Exploring new methods of generating electricity, such as through renewable sources (*e.g.*, wind, solar).
- Enhancing energy trading infrastructure.
- Developing more efficient methods of operating generating plants.

- Optimizing and efficiently managing generation and other energy-related assets.
- Reducing emissions resulting from the burning of fossil fuels (coal and natural gas).
- Improving the efficiency, utilization and reliability of the transmission and distribution systems.
- Exploring the application of new technologies.

AEP System operating companies are members of the Electric Power Research Institute (EPRI), an organization founded in 1973 that manages science and technology initiatives on behalf of its members. EPRI's members include investor owned and public utilities, independent power producers, international organizations and others.

AEP participates in EPRI programs that meet its research and development objectives. Total AEP dues to EPRI were $9,000,000 for 2001, $17,000,000 for 2000 and $22,000,000 for 1999. Of these amounts, the former CSW System paid approximately $7,000,000 in 2000 and $8,000,000 in 1999 for EPRI programs.

Total research and development expenditures by AEP and its subsidiaries, including EPRI dues, were approximately $15,000,000 for 2001, $20,000,000 for 2000 and $25,000,000 for 1999.

Item 2. **Properties**

At December 31, 2001, the AEP System owned (or leased where indicated) generating plants with net power capabilities (east zone subsidiaries-winter rating; west zone subsidiaries-summer rating) shown in the following table:

Company	Stations	Coal MW	Natural Gas MW	Hydro MW	Nuclear MW	Lignite MW	Other MW	Total MW
AEGCo	1(a)	1,300						1,300
APCo	17(b)	5,081		777				5,858
CPL	12(c)(d)	686	3,175	6	630			4,497
CSPCo	6(e)	2,595						2,595
I&M	10(a)	2,295		11	2,110			4,416
KEPCo	1	1,060						1,060
OPCo	8(b)(f)	8,464		48				8,512
PSO	8(c)	1,043	3,169				25(g)	4,237
SWEPCo	9	1,848	1,797			842		4,487
WTU	12(c)	377	999				16(g)	1,392
Totals:	84	24,749	9,140	842	2,740	842	41	38,354

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.
(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.
(c) CPL, PSO, and WTU jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.
(d) Reflects CPL's interest in STP.
(e) CSPCo owns generating units in common with CG&E and DP&L. Its ownership interest of 1,330 MW is reflected in this table.
(f) The scrubber facilities at the General James M. Gavin Plant are leased. The lease terminates in 2010 unless extended.
(g) PSO and WTU have 25 MW and 10 MW respectively of facilities designed primarily to burn oil. WTU has one 6 MW wind farm facility.

AEP-Other Generation: In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities, both foreign and domestic. Information concerning these facilities at December 31, 2001 is listed below (except for Bajio which went into commercial operation in March 2002).

Facility	Fuel	Location	Capacity Total MW	Ownership Interest	Status
Brush II	Natural gas	Colorado	68	47.75%	QF
Eastex	Natural gas	Texas	440	50%	QF
Indian Mesa	Wind	Texas	161	100%	EWG
Mulberry	Natural gas	Florida	120	46.25%	QF
Newgulf	Natural gas	Texas	85	100%	EWG
Orange Cogen	Natural gas	Florida	103	50%	QF
Sweeny	Natural gas	Texas	480	50%	QF
Thermo Cogeneration	Natural gas	Colorado	272	50%	QF
Trent Wind Farm	Wind	Texas	150	100%	EWG
Total U.S.			1,879		
Bajio	Natural gas	Mexico	605	50%	FUCO
Bakun	Hydro	Philippines	70	10%	FUCO
Codrington	Wind	Australia	18	20%	FUCO
Ferrybridge	Coal	United Kingdom	2,000	100%	FUCO
Fiddler's Ferry	Coal	United Kingdom	2,000	100%	FUCO
Medway	Natural gas	United Kingdom	675	37.5%	FUCO
Nanyang	Coal	China	250	70%	FUCO
Ord Hydro	Hydro	Australia	30	20%	FUCO
Southcoast	Natural gas	United Kingdom	380	50%	FUCO
Vale	Hydro/Thermal	Brazil	665	(a)	FUCO
Victoria	Hydro	Australia	10	20%	FUCO
Total International			6,703		

(a) AEP has varying minority interests which aggregate to 168 MW.

See Item 1 under *Fuel Supply* for information concerning coal reserves owned or controlled by subsidiaries of AEP and under *Wholesale Business Operations* for information concerning AEP's natural gas pipeline, storage and processing facilities.

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765,000-volt lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765,000-volt Lines
AEP System (a)	211,300(b)	2,023
APCo	51,295	642
CPL	31,210	---
CSPCo (a)	13,703	---
I&M	20,672	614
KEPCo	10,443	258
OPCo	29,347	509
PSO	18,713	---
SWEPCo	19,873	---
WTU	12,605	---

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of transmission lines not identified with an operating company.

Titles

The AEP System's electric generating stations are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of the System in the realty on which its facilities are located are considered by it to be adequate for its use in the conduct of its business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. System companies generally have the right of eminent domain whereby they may, if necessary, acquire, perfect or secure titles to or easements on privately-held lands used or to be used in their utility operations.

Substantially all the fixed physical properties and franchises of the AEP System operating companies, except for limited conditions and limitations, are subject to the lien of the mortgage and deed of trust securing the first mortgage bonds of each such company.

System Transmission Lines and Facility Siting

Legislation in the states of Arkansas, Indiana, Kentucky, Michigan, Ohio, Texas, Virginia, and West Virginia requires prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. Delays and additional costs in constructing facilities have been experienced as a result of proceedings conducted pursuant to such statutes, as well as in proceedings in which operating companies have sought to acquire rights-of-way through condemnation, and such proceedings may result in additional delays and costs in future years.

Peak Demand

The east zone system is interconnected through 121 high-voltage transmission interconnections with 25 neighboring electric utility systems. The all-time and 2001 one-hour peak system demands were 25,940,000 and 25,433,000 kilowatts, respectively (which included 7,314,000 and 5,469,000 kilowatts, respectively, of scheduled deliveries to unaffiliated systems which the system might, on appropriate notice, have elected not to schedule for delivery) and occurred on June 17, 1994 and July 24, 2001, respectively. The net dependable capacity to serve the system load on such date, including power available under contractual obligations, was 23,457,000 and 23,974,000 kilowatts, respectively. The all-time and 2001 one-hour internal peak demand was 20,218,000 kilowatts, and occurred on August 8, 2001. The net dependable capacity to serve the system load on such date, including power dedicated under contractual arrangements, was 23,935,000 kilowatts. The all-time one-hour integrated and internal net system peak demands and 2001 peak demands for the east zone generating subsidiaries are shown in the following tabulation:

	All-time one-hour integrated net system peak demand		2001 one-hour integrated net system peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
APCo........	8,303	January 17, 1997	7,750	January 10, 2001
CSPCo......	4,833	July 23, 2001	4,833	July 23, 2001
I&M.........	5,403	June 23, 2001	5,403	July 23, 2001
KEPCo.....	1,860	January 10, 2001	1,860	January 10, 2001
OPCo........	7,291	June 17, 1994	6,668	July 24, 2001

	All-time one-hour integrated net internal peak demand		2001 one-hour integrated net internal peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
APCo.........	6,908	February 5, 1996	6,402	January 3, 2001
CSPCo........	3,927	August 8, 2001	3,927	August 8, 2001
I&M...........	4,232	August 8, 2001	4,232	August 8, 2001
KEPCo.......	1,579	January 3, 2001	1,579	January 3, 2001
OPCo..........	5,705	June 11, 1999	5,341	July 24, 2001

The all-time and 2001 one-hour internal peak demand for the west zone system was 15,048,000 and 14,648,000 kilowatts, respectively, and occurred on August 31, 2000 and July 23, 2001, respectively. The all-time one-hour internal net system peak demands and 2001 peak demands for the west zone generating subsidiaries are shown in the following tabulation:

	All-time one-hour integrated net internal peak demand		2001 one-hour integrated net internal peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
CPL	4,623	September 5, 2000	4,323	June 12, 2001
PSO	3,823	August 30, 2000	3,785	August 9, 2001
SWEPCo	4,625	August 31, 2000	4,344	July 18, 2001
WTU	1,537	September 5, 2000	1,472	July 19, 2001

Hydroelectric Plants

AEP has 18 hydro facilities, of which 16 are licensed through FERC. The license for the Elkhart hydroelectric plant in Indiana was issued in January 2001 and extends for a period of thirty years. The license for the Mottville hydroelectric plant in Michigan expires in 2003 and the application for a new license was filed with FERC in September 2001.

Cook Nuclear Plant and STP

The following table provides operating information relating to the Cook Plant and STP.

	Cook Plant		STP(a)	
	Unit 1	Unit 2	Unit 1	Unit 2
Year Placed in Operation	1975	1978	1988	1989
Year of Expiration of NRC License (b)	2014	2017	2027	2028
Nominal Net Electrical Rating in Kilowatts	1,020,000	1,090,000	1,250,600	1,250,600
Net Capacity Factors				
2001 (c)	87.3%	83.4%	94.4%	87.1%
2000 (d)	1.4%	50.0%	78.2%	96.1%

(a) Reflects total plant.
(b) For economic or other reasons, operation of the Cook Plant and STP for the full term of their operating licenses cannot be assured.
(c) The capacity factor for both units of the Cook Plant was significantly reduced in 2001 due to an unplanned dual maintenance outage in September 2001 to implement design changes that improved the performance of the essential service water system.
(d) The Cook Plant was shut down in September 1997 to respond to issues raised regarding the operability of certain safety systems. The restart of both units of the Cook Plant was completed with Unit 2 reaching 100% power on July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001.

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be of greater significance and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the construction and operation of nuclear facilities. I&M and CPL may also incur costs and experience reduced output at Cook Plant and STP, respectively, because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant and STP initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M and CPL to obtain adequate and timely recovery of costs associated with the Cook Plant and STP, respectively, including replacement power, any unamortized investment at the end of the useful life of the Cook Plant and STP (whether scheduled or premature), the carrying costs of that investment and retirement costs, is not assured. See *Competition and Business Change.*

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless allowed to be recovered through rates, could have a material adverse effect on results of operations and the financial condition of AEP, CPL, I&M and other AEP System companies.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* that is incorporated by reference in Item 8 for information with respect to nuclear incident liability insurance.

Federal EPA Notice of Violation to OPCo: On August 31, 2000, Region V, Federal EPA, issued a Notice of Violation (NOV) to OPCo's Gavin Plant that alleges violations of the Federal EPA-approved Ohio mass particulate emission limit, opacity, and air pollution nuisance rules. AEP has submitted information in response to the allegations and requested a conference to discuss the NOV with Region V representatives.

Ohio EPA Notices of Violation to OPCo: On August 17, 2001, Ohio EPA issued proposed findings and orders to OPCo's Gavin Plant based on the alleged failure of a mass particulate emissions test on May 17, 2000. OPCo requested a conference to discuss the proposed findings and orders and submitted the results of its investigation of the test procedures, which confirmed that the May 17 test was invalid due to the corrosion and disintegration of the test probe.

On December 27, 2001, Ohio EPA issued two NOVs to OPCo's Gavin Plant, alleging that OPCo failed to notify Ohio EPA of a malfunction of the flyash handling system at the plant, and that OPCo failed to conduct a required mass particulate emissions test. OPCo has submitted additional control plans for the flyash handling system and information regarding the particulate testing completed at the Gavin Plant in response to the NOVs.

COLI Litigation: On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced in 2000 as follows:

	(in millions)
AEP System operating companies......	$ 319
APCo	82
CSPCo	41
I&M	66
KEPCo	8
OPCo	118

The Company has filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the Sixth Circuit.

See Item 1 for a discussion of certain environmental matters.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Item 8 for further information with respect to other legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

AEP, APCo, CPL, I&M, OPCo and SWEPCo. None.

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

Executive Officers of the Registrants

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of March 1, 2002.

Name	Age	Office (a)
E. Linn Draper, Jr.	60	Chairman of the Board, President and Chief Executive Officer of AEP and of the Service Corporation
Thomas V. Shockley, III	56	Vice Chairman and Chief Operating Officer of the Service Corporation
Henry W. Fayne	55	Executive Vice President of the Service Corporation
Robert P. Powers	48	Executive Vice President-Nuclear Generation and Technical Services of the Service Corporation
Susan Tomasky	48	Executive Vice President-Policy, Finance and Strategic Planning of the Service Corporation
J. H. Vipperman	61	Executive Vice President-Shared Services of the Service Corporation

(a) All of the executive officers listed above have been employed by the Service Corporation or System companies in various capacities (AEP, as such, has no employees) during the past five years, except for Messrs. Powers and Shockley and Ms. Tomasky. Prior to joining the Service Corporation in July 1998 as Senior Vice President-Generation, Mr. Powers was Vice President of Pacific Gas & Electric and plant manager of its Diablo Canyon Nuclear Generating Station (1996-1998). Prior to joining the Service Corporation in July 1998 as Senior Vice President, Ms. Tomasky was a partner with the law firm of Hogan & Hartson (August 1997-July 1998) and General Counsel of the Federal Energy Regulatory Commission (May 1993-August 1997). Mr. Powers and Ms. Tomasky became executive officers of AEP effective with their promotions to Executive Vice President on October 24, 2001 and January 26, 2000, respectively. Prior to joining the Service Corporation in his current position upon the merger with CSW, Mr. Shockley was President and Chief Operating Officer of CSW (1997-2000) and Executive Vice President of CSW (1990-1997). All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of the Service Corporation, or both, as the case may be.

APCo, CPL, I&M, OPCo and SWEPCo. The names of the executive officers of APCo, CPL, I&M, OPCo and SWEPCo, the positions they hold with these companies, their ages as of March 1, 2002, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, CPL, I&M, OPCo and SWEPCo are elected annually to serve a one-year term.

Name	Age	Position (a)(b)	Period
E. Linn Draper, Jr.	60	Director of CPL and SWEPCo	2000-Present
		Chairman of the Board and Chief Executive Officer of CPL and SWEPCo	2000-Present
		Director of APCo, I&M and OPCo	1992-Present
		Chairman of the Board and Chief Executive Officer of APCo, I&M and OPCo	1993-Present
		Chairman of the Board, President and Chief Executive Officer of AEP and the Service Corporation	1993-Present

Name	Age	Position (a)(b)	Period
Thomas V. Shockley, III ..	56	Director and Vice President of APCo, CPL, I&M, OPCo and SWEPCo	2000-Present
		Chief Operating Officer of the Service Corporation	2001-Present
		Vice Chairman of AEP and the Service Corporation	2000-Present
		President and Chief Operating Officer of CSW	1997-2000
		Executive Vice President of CSW	1990-1997
Henry W. Fayne	55	President of APCo, CPL, I&M, OPCo and SWEPCo	2001-Present
		Director of CPL and SWEPCO	2000-Present
		Director of APCo	1995-Present
		Director of OPCo	1993-Present
		Director of I&M	1998-Present
		Vice President of CPL and SWEPCo	2000-2001
		Vice President of APCo, I&M and OPCo	1998-2001
		Vice President of AEP	1998-Present
		Chief Financial Officer of AEP	1998-2001
		Executive Vice President of the Service Corporation	2001-Present
		Executive Vice President-Finance and Analysis of the Service Corporation	2000-2001
		Executive Vice President-Financial Services of the Service Corporation	1998-2000
		Senior Vice President-Corporate Planning & Budgeting of the Service Corporation	1995-1998
Robert P. Powers	48	Director and Vice President of APCo, CPL, OPCo and SWEPCo	2001-Present
		Director of I&M	2001-Present
		Vice President of I&M	1998-Present
		Executive Vice President-Nuclear Generation and Technical Services of the Service Corporation	2001-Present
		Senior Vice President-Nuclear Operations of the Service Corporation	2000-2001
		Senior Vice President-Nuclear Generation of the Service Corporation	1998-2000
		Vice President of Pacific Gas & Electric and Plant Manager of its Diablo Canyon Nuclear Generating Station	1996-1998
Susan Tomasky	48	Director and Vice President of APCo, CPL, I&M, OPCo and SWEPCo	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of the Service Corporation	2001-Present
		Executive Vice President-Legal, Policy and Corporate Communications and General Counsel of the Service Corporation	2000-2001
		Senior Vice President and General Counsel of the Service Corporation	1998-2000
		Hogan & Hartson (law firm)	1997-1998
		General Counsel of the FERC	1993-1997

Name	Age	Position (a)(b)	Period
J. H. Vipperman	61	Director and Vice President of CPL and SWEPCo	2000-Present
		Director of APCo	1985-Present
		Director of I&M and OPCo	1996-Present
		Vice President of APCo, I&M and OPCo	1996-Present
		Executive Vice President-Shared Services of the Service Corporation	2000-Present
		Executive Vice President-Corporate Services of the Service Corporation	1998-2000
		Executive Vice President-Energy Delivery of the Service Corporation	1996-1997

(a) Dr. Draper is a director of BCP Management, Inc., which is the general partner of Borden Chemicals and Plastics L.P.

(b) Dr. Draper, Messrs. Fayne, Powers, Shockley and Vipperman and Ms. Tomasky are directors of AEGCo, CSPCo, KEPCo, PSO and WTU. Dr. Draper and Mr. Shockley are also directors of AEP.

PART II

Item 5. Market for Registrants' Common Equity and Related Stockholder Matters

AEP. The information required by this item is incorporated herein by reference to the material under *Common Stock and Dividend Information* in the 2001 Annual Report.

AEGCo, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2001 and 2000 are incorporated by reference to the material under *Statement of Retained Earnings* in the 2001 Annual Reports.

Item 6. Selected Financial Data

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, CPL, I&M, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2001 Annual Reports.

Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Narrative Analysis of Results of Operations* in the 2001 Annual Reports.

AEP, APCo, CPL, I&M, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the 2001 Annual Reports.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to the material under *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the 2001 Annual Reports.

Item 8. Financial Statements and Supplementary Data

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to the financial statements and supplementary data described under Item 14 herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

AEGCo, AEP, APCo, CSPCo, I&M, KEPCo and OPCo. None.

CPL, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to each company's Current Report on Form 8-K dated July 5, 2000.

PART III

Item 10. Directors and Executive Officers of the Registrants

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Nominees for Director* and *Section 16(a) Beneficial Ownership Reporting Compliance* of the definitive proxy statement of AEP for the 2002 annual meeting of shareholders, to be filed within 120 days after December 31, 2001. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of each company for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

CPL and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of APCo for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M. The names of the directors and executive officers of I&M, the positions they hold with I&M, their ages as of March 12, 2002, and a brief account of their business experience during the past five years appear below and under the caption *Executive Officers of the Registrants* in Part I of this report.

Name	Age	Position (a)	Period
K. G. Boyd	50	Director	1997-Present
		Vice President – Fort Wayne Region Distribution Operations	2000-Present
		Indiana Region Manager	1997-2000
		Fort Wayne District Manager	1994-1997
John E. Ehler	45	Director	2001-Present
		Manager of Distribution Systems-Fort Wayne District	2000-Present
		Region Operations Manager	1997-2000
David L. Lahrman	50	Director and Manager, Region Support	2001-Present
		Fort Wayne District Manager	1997-2001
		Region Operations Manager	1994-1997
Marc E. Lewis	47	Director	2001-Present
		Assistant General Counsel of the Service Corporation	2001-Present
		Senior Counsel of the Service Corporation	2000-2001
		Senior Attorney of the Service Corporation	1994-2000
Susanne M. Moorman	52	Director and General Manager, Community Services	2000-Present
		Manager, Customer Services Operations	1997-2000
		Director, Customer Services	1994-1997
John R. Sampson	49	Director and Vice President	1999-Present
		Indiana State President	2000-Present
		Indiana & Michigan State President	1999-2000
		Site Vice President, Cook Nuclear Plant	1998-1999
		Plant Manager, Cook Nuclear Plant	1996-1998
D. B. Synowiec..................	58	Director	1995-Present
		Plant Manager, Rockport Plant	1990-Present

(a) Positions are with I&M unless otherwise indicated.

Item 11. Executive Compensation

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership Guidelines, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2002 annual meeting of shareholders to be filed within 120 days after December 31, 2001.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001.

CPL, I&M and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of APCo for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001.

Item 12. **Security Ownership of Certain Beneficial Owners and Management**

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2002 annual meeting of shareholders to be filed within 120 days after December 31, 2001.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001.

CPL and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of APCo for the 2002 annual meeting of stockholders, to be filed within 120 days after December 31, 2001.

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2002, by each director and nominee of I&M and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares (a)	Stock Units (b)	Total
Karl G. Boyd	6,964	88	7,052
E. Linn Draper, Jr.	238,274(c)	119,218	357,492
John E. Ehler	7	—	7
Henry W. Fayne	72,685(d)	13,735	86,420
David L. Lahrman	360	—	360
Marc E. Lewis	1,117	—	1,117
Susanne M. Moorman	841	—	841
Robert P. Powers	21,269	1,209	22,478
John R. Sampson	5,525	109	5,634
Thomas V. Shockley, III	138,822(d)(e)	—	138,822
David B. Synowiec	2,361	129	2,490
Susan Tomasky	67,322	4,329	71,651
Joseph H. Vipperman	78,043(c)(d)	7,201	85,244
All Directors and Executive Officers	633,590(d)(f)	146,018	779,608

(a) Includes share equivalents held in the AEP Retirement Savings Plan (and for Mr. Shockley, the CSW Retirement Savings Plan) in the amounts listed below:

Name	AEP Retirement Savings Plan (Share Equivalents)	Name	AEP Retirement Savings Plan (Share Equivalents)
Mr. Boyd	1,964	Mr. Powers	436
Dr. Draper	4,280	Mr. Sampson	525
Mr. Ehler	7	Mr. Shockley	6,579
Mr. Fayne	5,412	Mr. Synowiec	695
Mr. Lahrman	360	Ms. Tomasky	656
Mr. Lewis	1,117	Mr. Vipperman	10,498
Ms. Moorman	841	All Directors and Executive Officers	33,370

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan.
Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Boyd, 5,000; Dr. Draper, 233,333; Mr. Powers, 20,833; Mr. Sampson, 5,000; Mr. Shockley, 94,450; Mr. Synowiec, 1,666; and Messrs. Fayne and Vipperman and Ms. Tomasky, 66,666.

(b) This column includes amounts deferred in stock units and held under AEP's officer benefit plans.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Dr. Draper, 661; and Mr. Vipperman, 80.

(d) Does not include, for Messrs. Fayne, Shockley and Vipperman, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne, Shockley and Vipperman 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

(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Mr. Shockley, 496.

(f) Represents less than 1% of the total number of shares outstanding

Item 13. Certain Relationships and Related Transactions

AEP, APCo, CPL, I&M, OPCo and SWEPCo. None.

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) The following documents are filed as a part of this report:

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

Page

AEGCo:

Independent Auditors' Report; Statements of Income for the years ended December 31, 2001, 2000, and 1999; Statements of Retained Earnings for the years ended December 31, 2001, 2000 and 1999; Statements of Cash Flows for the years ended December 31, 2001, 2000, and 1999; Balance Sheets as of December 31, 2001 and 2000; Statements of Capitalization as of December 31, 2001 and 2000; Combined Notes to Financial Statements.

AEP and its subsidiaries consolidated:

Consolidated Statements of Income for the years ended December 31, 2001, 2000, and 1999; Consolidated Balance Sheets as of December 31, 2001 and 2000; Consolidated

2. FINANCIAL STATEMENT SCHEDULES:

	Page
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable).	S-1
Independent Auditors' Report	S-2

3. EXHIBITS:

Exhibits for AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU are listed in the Exhibit Index and are incorporated herein by reference	E-1

(b) No Reports on Form 8-K were filed during the quarter ended December 31, 2001.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

BY: /S/ SUSAN TOMASKY
(Susan Tomasky, Vice President, Secretary and Chief Financial Officer)

Date: March 18, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) **Principal Executive Officer:**		
*E. LINN DRAPER, JR.	Chairman of the Board, President, Chief Executive Officer And Director	
(ii) **Principal Financial Officer:**		
/S/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President, Secretary and Chief Financial Officer	March 18, 2002
(iii) **Principal Accounting Officer:**		
/S/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 18, 2002
(iv) **A Majority of the Directors**:		
*E. R. BROOKS *DONALD M. CARLTON *JOHN P. DESBARRES *ROBERT W. FRI *WILLIAM R. HOWELL *LESTER A. HUDSON, JR. *LEONARD J. KUJAWA *JAMES L. POWELL *RICHARD L. SANDOR *THOMAS V. SHOCKLEY, III *DONALD G. SMITH *LINDA GILLESPIE STUNTZ *KATHRYN D. SULLIVAN		March 18, 2002

*By: /S/ SUSAN TOMASKY
(Susan Tomasky, Attorney-in-Fact)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP GENERATING COMPANY
APPALACHIAN POWER COMPANY
CENTRAL POWER AND LIGHT COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY
WEST TEXAS UTILITIES COMPANY

BY: /S/ SUSAN TOMASKY
(Susan Tomasky, Vice President)

Date: March 18, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director	
(ii) Principal Financial Officer:		
/S/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President And Director	March 18, 2002
(iii) Principal Accounting Officer:		
/S/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 18, 2002
(iv) A Majority of the Directors:		
*HENRY W. FAYNE *A. A. PENA *ROBERT P. POWERS *THOMAS V. SHOCKLEY, III *J. H. VIPPERMAN		
*By: /S/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 18, 2002

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

INDIANA MICHIGAN POWER COMPANY

BY: /S/ SUSAN TOMASKY
(Susan Tomasky, Vice President)

Date: March 18, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) **Principal Executive Officer:**		
*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director	
(ii) **Principal Financial Officer:**		
/S/ SUSAN TOMASKY **(Susan Tomasky)**	Vice President And Director	March 18, 2002
(iii) **Principal Accounting Officer:**		
/S/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 18, 2002
(iv) **A Majority of the Directors:**		
*K. G. BOYD		
*JOHN E. EHLER		
*HENRY W. FAYNE		
*DAVID L. LAHRMAN		
*MARC E. LEWIS		
*SUSANNE M. MOORMAN		
*ROBERT P. POWERS		
*JOHN R. SAMPSON		
*THOMAS V. SHOCKLEY, III		
*D. B. SYNOWIEC		
*J. H. VIPPERMAN		
*By: /s/ SUSAN TOMASKY **(Susan Tomasky, Attorney-in-Fact)**		March 18, 2002

INDEX TO FINANCIAL STATEMENT SCHEDULES

INDEPENDENT AUDITORS' REPORT

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and its subsidiaries and the financial statements of certain of its subsidiaries, listed in Item 14 herein, as of December 31, 2001 and 2000, and for each of the three years in the period ended December 31, 2001, and have issued our reports thereon dated February 22, 2002; such financial statements and reports are included in the 2001 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries, listed in Item 14, except for the financial statement schedules of Central Power and Light Company and subsidiary, Public Service Company of Oklahoma and its subsidiaries, Southwestern Electric Power Company and subsidiaries, and West Texas Utilities Company for the year ended December 31, 1999 and the financial information of Central and South West Corporation and its subsidiaries that is included in the financial statement schedule for American Electric Power Company, Inc. and its subsidiaries for the year ended December 31, 1999. These financial statement schedules are the responsibility of the respective company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001	$71,722	$124,542	$19,766(a)	$106,589(b)	$109,441
Year Ended December 31, 2000	$63,207	$ 70,670	$ 8,358(a)	$ 70,513(b)	$ 71,722
Year Ended December 31, 1999	$52,543	$ 38,347	$15,802(a)	$ 43,485(b)	$ 63,207

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001	$2,588	$2,644	$1,017(a)	$4,372(b)	$1,877
Year Ended December 31, 2000	$2,609	$6,592	$1,526(a)	$8,139(b)	$2,588
Year Ended December 31, 1999	$2,234	$5,492	$1,995(a)	$7,112(b)	$2,609

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

CENTRAL POWER AND LIGHT AND SUBSIDIARY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001	$1,675	$ 186	$ — (a)	$1,675(b)	$ 186
Year Ended December 31, 2000	$ —	$1,675	$ — (a)	$ — (b)	$1,675
Year Ended December 31, 1999	$ —	$ —	$ — (a)	$ — (b)	$ —

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$ 659	$ 331	$ — (a)	$ 245(b)	$ 745
Year Ended December 31, 2000........	$3,045	$2,082	$ 1,405(a)	$ 5,873(b)	$ 659
Year Ended December 31, 1999........	$2,598	$3,334	$10,782(a)	$13,669(b)	$3,045

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$ 759	$ 65	$ 3(a)	$ 86(b)	$ 741
Year Ended December 31, 2000........	$1,848	$ (235)	$ 907(a)	$1,761(b)	$ 759
Year Ended December 31, 1999........	$2,027	$3,966	$1,367(a)	$5,512(b)	$1,848

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

KENTUCKY POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$282	$ —	$(24)(a)	$ (6)(b)	$264
Year Ended December 31, 2000........	$637	$ 187	$ 9(a)	$ 551(b)	$282
Year Ended December 31, 1999........	$848	$1,032	$ 467(a)	$1,710(b)	$637

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

OHIO POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$1,054	$ 554	$ — (a)	$ 229(b)	$1,379
Year Ended December 31, 2000........	$2,223	$ 472	$ 778(a)	$2,419(b)	$1,054
Year Ended December 31, 1999........	$1,678	$4,730	$1,273(a)	$5,458(b)	$2,223

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$ 467	$ 44	$ — (a)	$ 467(b)	$ 44
Year Ended December 31, 2000........	$—	$ 467	$ — (a)	$ — (b)	$ 467
Year Ended December 31, 1999........	$—	$ —	$ — (a)	$ — (b)	$—

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001........	$ 911	$ 89	$ — (a)	$ 911(b)	$ 89
Year Ended December 31, 2000........	$4,428	$ 911	$(4,428)(a)	$ — (b)	$ 911
Year Ended December 31, 1999........	$3,269	$5,415	$ — (a)	$4,256(b)	$4,428

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

WEST TEXAS UTILITIES COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2001	$288	$ 13	$35(a)	$ 140(b)	$196
Year Ended December 31, 2000	$186	$1,499	$46(a)	$1,443(b)	$288
Year Ended December 31, 1999	$497	$ (66)	$43(a)	$ 288(b)	$186

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

EXHIBIT INDEX

Certain of the following exhibits, designated with an asterisk(*), are filed herewith. The exhibits not so designated have heretofore been filed with the Commission and, pursuant to 17 C.F.R. 229.10(d) and 240.12b-32, are incorporated herein by reference to the documents indicated in brackets following the descriptions of such exhibits. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an exhibit to this form pursuant to Item 14(c) of this report.

Exhibit Number		Description
AEGCo		
3(a)	—	Copy of Articles of Incorporation of AEGCo [Registration Statement on Form 10 for the Common Shares of AEGCo, File No. 0-18135, Exhibit 3(a)].
3(b)	—	Copy of the Code of Regulations of AEGCo (amended as of June 15, 2000) [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 2000, File No. 0-18135, Exhibit 3(b)].
10(a)	—	Copy of Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP [Registration Statement No. 33-32752, Exhibit 28(a)].
10(b)(1)	—	Copy of Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended [Registration Statement No. 33-32752, Exhibits 28(b)(1)(A) and 28(b)(1)(B)].
10(b)(2)	—	Copy of Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KEPCo [Registration Statement No. 33-32752, Exhibit 28(b)(2)].
10(b)(3)	—	Copy of Agreement, dated as of October 1, 1984, among AEGCo, I&M, APCo and Virginia Electric and Power Company [Registration Statement No. 33-32752, Exhibit 28(b)(3)].
10(c)	—	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B)].
*13	—	Copy of those portions of the AEGCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*24	—	Power of Attorney.
AEP‡		
3(a)	—	Copy of Restated Certificate of Incorporation of AEP, dated October 29, 1997 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1997, File No. 1-3525, Exhibit 3(a)].
3(b)	—	Copy of Certificate of Amendment of the Restated Certificate of Incorporation of AEP, dated January 13, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(b)].
3(c)	—	Composite copy of the Restated Certificate of Incorporation of AEP, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(c)].
3(d)	—	Copy of By-Laws of AEP, as amended through January 28, 1998 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 3(b)].
*4(a)	—	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.

Exhibit Number		Description
*4(b)	—	First Supplemental Indenture, dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee, for 6.125% Senior Notes, Series A, due May 15, 2006.
*4(c)	—	Second Supplemental Indenture, dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee, for 5.50% Putable Callable Notes, Series B, Putable Callable May 15, 2003.
10(a)	—	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(c)	—	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); and Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(d)	—	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
10(e)	—	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(f)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(f)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of AEP dated December 15, 1999, File No. 1-3525, Exhibit 10].
†10(g)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(g)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(h)	—	AEP Accident Coverage Insurance Plan for directors [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(g)].

Exhibit Number		Description
†10(i)(1)	—	AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended June 1, 2000 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(i)(1)].
*†10(i)(2)	—	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended January 1, 2002.
†10(j)(1)(A)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
†10(j)(1)(B)	—	Guaranty by AEP of the Service Corporation Excess Benefits Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(h)(1)(B)].
†10(j)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of June 1, 2001 (Non-Qualified) [Registration Statement No. 333-66048, Exhibit 4].
†10(j)(3)	—	Service Corporation Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(k)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(l)	—	AEP System Senior Officer Annual Incentive Compensation Plan[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
†10(m)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(n)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
*†10(o)	—	AEP Change In Control Agreement.
†10(p)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
†10(q)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
†10(r)(1)	—	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997 [Annual Report on Form 10-K of CSW for the fiscal year ended December 31, 1998, File No. 1-1443, Exhibit 18].
*†10(r)(2)	—	Certified CSW Board Resolution of April 18, 1991.
†10(r)(3)	—	CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the AEP 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*21	—	List of subsidiaries of AEP.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*23(c)	—	Consent of KPMG Audit plc.
*24	—	Power of Attorney.

Exhibit Number		Description
APCo‡		
3(a)	—	Copy of Restated Articles of Incorporation of APCo, and amendments thereto to November 4, 1993 [Registration Statement No. 33-50163, Exhibit 4(a); Registration Statement No. 33-53805, Exhibits 4(b) and 4(c)].
3(b)	—	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated June 6, 1994 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1994, File No. 1-3457, Exhibit 3(b)].
3(c)	—	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated March 6, 1997 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(c)].
3(d)	—	Composite copy of the Restated Articles of Incorporation of APCo (amended as of March 7, 1997) [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(d)].
*3(e)	—	Copy of By-Laws of APCo (amended as of October 24, 2001).
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of December 1, 1940, between APCo and Bankers Trust Company and R. Gregory Page, as Trustees, as amended and supplemented [Registration Statement No. 2-7289, Exhibit 7(b); Registration Statement No. 2-19884, Exhibit 2(1); Registration Statement No. 2-24453, Exhibit 2(n); Registration Statement No. 2-60015, Exhibits 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), 2(b)(6), 2(b)(7), 2(b)(8), 2(b)(9), 2(b)(10), 2(b)(12), 2(b)(14), 2(b)(15), 2(b)(16), 2(b)(17), 2(b)(18), 2(b)(19), 2(b)(20), 2(b)(21), 2(b)(22), 2(b)(23), 2(b)(24), 2(b)(25), 2(b)(26), 2(b)(27) and 2(b)(28); Registration Statement No. 2-64102, Exhibit 2(b)(29); Registration Statement No. 2-66457, Exhibits (2)(b)(30) and 2(b)(31); Registration Statement No. 2-69217, Exhibit 2(b)(32); Registration Statement No. 2-86237, Exhibit 4(b); Registration Statement No. 33-11723, Exhibit 4(b); Registration Statement No. 33-17003, Exhibit 4(a)(ii), Registration Statement No. 33-30964, Exhibit 4(b); Registration Statement No. 33-40720, Exhibit 4(b); Registration Statement No. 33-45219, Exhibit 4(b); Registration Statement No. 33-46128, Exhibits 4(b) and 4(c); Registration Statement No. 33-53410, Exhibit 4(b); Registration Statement No. 33-59834, Exhibit 4(b); Registration Statement No. 33-50229, Exhibits 4(b) and 4(c); Registration Statement No. 33-58431, Exhibits 4(b), 4(c), 4(d) and 4(e); Registration Statement No. 333-01049, Exhibits 4(b) and 4(c); Registration Statement No. 333-20305, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 4(b); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1998, File No. 1-3457, Exhibit 4(b)].
4(b)	—	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee [Registration Statement No. 333-45927, Exhibit 4(a); Registration Statement No. 333-49071, Exhibit 4(b); Registration Statement No. 333-84061, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1999, File No. 1-3457, Exhibit 4(c); Registration Statement No. 333-81402, Exhibits 4(b), 4(c) and 4(d)].

Exhibit Number		Description
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(e)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of APCo dated December 15, 1999, File No. 1-3457, Exhibit 10].
†10(f)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(f)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(g)	—	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].

Exhibit Number		Description
†10(h)(1)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
†10(h)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
†10(h)(3)	—	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(i)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(j)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(k)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
†10(l)	—	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 10(o)].
†10(m)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
†10(n)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
†10(o)(1)	—	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997 [Annual Report on Form 10-K of CSW for the fiscal year ended December 31, 1998, File No. 1-1443, Exhibit 18].
†10(o)(2)	—	Certified CSW Board Resolution of April 18, 1991 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 10(r)(2)].
†10(o)(3)	—	CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the APCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
21	—	List of subsidiaries of APCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 21].
*24	—	Power of Attorney.
CPL‡		
3(a)	—	Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation [Quarterly Report on Form 10-Q of CPL for the quarter ended March 31, 1997, File No. 0-346, Exhibit 3.1].
3(b)	—	By-Laws of CPL (amended as of April 19, 2000) [Annual Report on Form 10-K of CPL for the fiscal year ended December 31, 2000, File No. 0-346, Exhibit 3(b)].

Exhibit Number		Description
4(a)	—	Indenture of Mortgage or Deed of Trust, dated November 1, 1943, between CPL and The First National Bank of Chicago and R. D. Manella, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.01; Registration Statement No. 2-62271, Exhibit 2.02; Form U-1 No. 70-7003, Exhibit 17; Registration Statement No. 2-98944, Exhibit 4 (b); Form U-1 No. 70-7236, Exhibit 4; Form U-1 No. 70-7249, Exhibit 4; Form U-1 No. 70-7520, Exhibit 2; Form U-1 No. 70-7721, Exhibit 3; Form U-1 No. 70-7725, Exhibit 10; Form U-1 No. 70-8053, Exhibit 10 (a); Form U-1 No. 70-8053, Exhibit 10 (b); Form U-1 No. 70-8053, Exhibit 10 (c); Form U-1 No. 70-8053, Exhibit 10 (d); Form U-1 No. 70-8053, Exhibit 10 (e); Form U-1 No. 70-8053, Exhibit 10 (f)].
4(b)	—	CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL: (1) Indenture, dated as of May 1, 1997, between CPL and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibits 4.1 and 4.2]. (2) Amended and Restated Trust Agreement of CPL Capital I, dated as of May 1, 1997, among CPL, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.3]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by CPL for the benefit of the holders of CPL Capital I's Preferred Securities [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.4]. (4) Agreement as to Expenses and Liabilities dated as of May 1, 1997, between CPL and CPL Capital I [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.5].
4(c)	—	Indenture (for unsecured debt securities), dated as of November 15, 1999, between CPL and The Bank of New York, as Trustee, as amended and supplemented [Annual Report on Form 10-K of CPL for the fiscal year ended December 31, 2000, File No. 0-346, Exhibits 4(c), 4(d) and 4(e)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the CPL 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
CSPCo‡		
3(a)	—	Copy of Amended Articles of Incorporation of CSPCo, as amended to March 6, 1992 [Registration Statement No. 33-53377, Exhibit 4(a)].
3(b)	—	Copy of Certificate of Amendment to Amended Articles of Incorporation of CSPCo, dated May 19, 1994 [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(b)].
3(c)	—	Composite copy of Amended Articles of Incorporation of CSPCo, as amended [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(c)].
3(d)	—	Copy of Code of Regulations and By-Laws of CSPCo [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1987, File No. 1-2680, Exhibit 3(d)].

Exhibit Number		Description
4(a)	—	Copy of Indenture of Mortgage and Deed of Trust, dated September 1, 1940, between CSPCo and City Bank Farmers Trust Company (now Citibank, N.A.), as trustee, as supplemented and amended [Registration Statement No. 2-59411, Exhibits 2(B) and 2(C); Registration Statement No. 2-80535, Exhibit 4(b); Registration Statement No. 2-87091, Exhibit 4(b); Registration Statement No. 2-93208, Exhibit 4(b); Registration Statement No. 2-97652, Exhibit 4(b); Registration Statement No. 33-7081, Exhibit 4(b); Registration Statement No. 33-12389, Exhibit 4(b); Registration Statement No. 33-19227, Exhibits 4(b), 4(e), 4(f), 4(g) and 4(h); Registration Statement No. 33-35651, Exhibit 4(b); Registration Statement No. 33-46859, Exhibits 4(b) and 4(c); Registration Statement No. 33-50316, Exhibits 4(b) and 4(c); Registration Statement No. 33-60336, Exhibits 4(b), 4(c) and 4(d); Registration Statement No. 33-50447, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1993, File No. 1-2680, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-54025, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1998, File No. 1-2680, Exhibits 4(c) and 4(d)].
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo, and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].

Exhibit Number		Description
10(e)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(e)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of CSPCo dated December 15, 1999, File No. 1-2680, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the CSPCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*23	—	Consent of Deloitte & Touche LLP.
*24	—	Power of Attorney.
I&M‡		
3(a)	—	Copy of the Amended Articles of Acceptance of I&M and amendments thereto [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 3(a)].
3(b)	—	Copy of Articles of Amendment to the Amended Articles of Acceptance of I&M, dated March 6, 1997 [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(b)].
3(c)	—	Composite Copy of the Amended Articles of Acceptance of I&M (amended as of March 7, 1997) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(c)].
*3(d)	—	Copy of the By-Laws of I&M (amended as of November 28, 2001).
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of June 1, 1939, between I&M and Irving Trust Company (now The Bank of New York) and various individuals, as Trustees, as amended and supplemented [Registration Statement No. 2-7597, Exhibit 7(a); Registration Statement No. 2-60665, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), (2)(c)(16), and 2(c)(17); Registration Statement No. 2-63234, Exhibit 2(b)(18); Registration Statement No. 2-65389, Exhibit 2(a)(19); Registration Statement No. 2-67728, Exhibit 2(b)(20); Registration Statement No. 2-85016, Exhibit 4(b); Registration Statement No. 33-5728, Exhibit 4(c); Registration Statement No. 33-9280, Exhibit 4(b); Registration Statement No. 33-11230, Exhibit 4(b); Registration Statement No. 33-19620, Exhibits 4(a)(ii), 4(a)(iii), 4(a)(iv) and 4(a)(v); Registration Statement No. 33-46851, Exhibits 4(b)(i), 4(b)(ii) and 4(b)(iii); Registration Statement No. 33-54480, Exhibits 4(b)(I) and 4(b)(ii); Registration Statement No. 33-60886, Exhibit 4(b)(I); Registration Statement No. 33-50521, Exhibits 4(b)(I), 4(b)(ii) and 4(b)(iii); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1994, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee [Registration Statement No. 333-88523, Exhibits 4(a), 4(b) and 4(c); Registration Statement No. 58656, Exhibits 4(b) and 4(c)].
* 4(c)	—	Copy of Company Order and Officers' Certificate, dated December 12, 2001, establishing certain terms of the 6.125% Notes, Series C, due 2006.

Exhibit Number		Description
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(a)(4)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(5)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M, and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 1, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)	—	Copy of Nuclear Material Lease Agreement, dated as of December 1, 1990, between I&M and DCC Fuel Corporation [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 10(d)].
10(f)	—	Copy of Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].

Exhibit Number		Description
10(g)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of I&M dated December 15, 1999, File No. 1-3570, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the I&M 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
21	—	List of subsidiaries of I&M [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 21].
*23	—	Consent of Deloitte & Touche LLP.
*24	—	Power of Attorney.
KEPCo‡		
3(a)	—	Copy of Restated Articles of Incorporation of KEPCo [Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1991, File No. 1-6858, Exhibit 3(a)].
3(b)	—	Copy of By-Laws of KEPCo (amended as of June 15, 2000) [Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 2000, File No. 1-6858, Exhibit 3(b)].
4(a)	—	Copy of Mortgage and Deed of Trust, dated May 1, 1949, between KEPCo and Bankers Trust Company, as supplemented and amended [Registration Statement No. 2-65820, Exhibits 2(b)(1), 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), and 2(b)(6); Registration Statement No. 33-39394, Exhibits 4(b) and 4(c); Registration Statement No. 33-53226, Exhibits 4(b) and 4(c); Registration Statement No. 33-61808, Exhibits 4(b) and 4(c), Registration Statement No. 33-53007, Exhibits 4(b), 4(c) and 4(d)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between KEPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-75785, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1999, File No. 1-6858, Exhibit 4(c); Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 2000, File No. 1-6858, Exhibit 4(c)].
10(a)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a);Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(c)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].

Exhibit Number		Description
10(d)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(d)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of KEPCo dated December 15, 1999, File No. 1-6858, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the KEPCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*24	—	Power of Attorney.
OPCo‡		
3(a)	—	Copy of Amended Articles of Incorporation of OPCo, and amendments thereto to December 31, 1993 [Registration Statement No. 33-50139, Exhibit 4(a); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 3(b)].
3(b)	—	Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated May 3, 1994 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 3(b)].
3(c)	—	Copy of Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated March 6, 1997 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(c)].
3(d)	—	Composite copy of the Amended Articles of Incorporation of OPCo (amended as of March 7, 1997) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(d)].
3(e)	—	Copy of Code of Regulations of OPCo [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1990, File No. 1-6543, Exhibit 3(d)].
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of October 1, 1938, between OPCo and Manufacturers Hanover Trust Company (now Chemical Bank), as Trustee, as amended and supplemented [Registration Statement No. 2-3828, Exhibit B-4; Registration Statement No. 2-60721, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), 2(c)(16), 2(c)(17), 2(c)(18), 2(c)(19), 2(c)(20), 2(c)(21), 2(c)(22), 2(c)(23), 2(c)(24), 2(c)(25), 2(c)(26), 2(c)(27), 2(c)(28), 2(c)(29), 2(c)(30), and 2(c)(31); Registration Statement No. 2-83591, Exhibit 4(b); Registration Statement No. 33-21208, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-31069, Exhibit 4(a)(ii); Registration Statement No. 33-44995, Exhibit 4(a)(ii); Registration Statement No. 33-59006, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-50373, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-49595, Exhibits 4(a), 4(b) and 4(c); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1998, File No. 1-6543, Exhibits 4(c) and 4(d); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1999, File No. 1-6543, Exhibits 4(c) and 4(d); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2000, File No. 1-6543, Exhibit 4(c)].

Exhibit Number		Description
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)	—	Copy of Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 10(f)].
10(f)	—	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
10(g)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of OPCo dated December 15, 1999, File No. 1-6543, Exhibit 10].

Exhibit Number		Description
†10(h)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(h)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(i)	—	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
†10(j)(1)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
†10(j)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
†10(j)(3)	—	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(k)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(l)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(m)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
†10(n)	—	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 10(o)].
†10(o)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
†10(p)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
†10(q)(1)	—	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997 [Annual Report on Form 10-K of CSW for the fiscal year ended December 31, 1998, File No. 1-1443, Exhibit 18].
†10(q)(2)	—	Certified CSW Board Resolution of April 18, 1991 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 10(r)(2)].
†10(q)(3)	—	CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the OPCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
21	—	List of subsidiaries of OPCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2001, File No. 1-3525, Exhibit 21].
*23	—	Consent of Deloitte & Touche LLP.
*24	—	Power of Attorney.

Exhibit Number		Description
PSO‡		
3(a)	—	Restated Certificate of Incorporation of PSO [Annual Report on Form U5S of Central and South West Corporation for the fiscal year ended December 31, 1996, File No. 1-1443, Exhibit B-3.1].
3(b)	—	By-Laws of PSO (amended as of June 28, 2000) [Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 2000, File No. 0-343, Exhibit 3(b)].
4(a)	—	Indenture, dated July 1, 1945, between PSO and Liberty Bank and Trust Company of Tulsa, National Association, as Trustee, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.03; Registration Statement No. 2-64432, Exhibit 2.02; Registration Statement No. 2-65871, Exhibit 2.02; Form U-1 No. 70-6822, Exhibit 2; Form U-1 No. 70-7234, Exhibit 3; Registration Statement No. 33-48650, Exhibit 4(b); Registration Statement No. 33-49143, Exhibit 4(c); Registration Statement No. 33-49575, Exhibit 4(b); Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 1993, File No. 0-343, Exhibit 4(b); Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.01; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.02; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.03].
4(b)	—	PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO: (1) Indenture, dated as of May 1, 1997, between PSO and The Bank of New York, as Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.6 and 4.7]. (2) Amended and Restated Trust Agreement of PSO Capital I, dated as of May 1, 1997, among PSO, as Depositor, The Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibit 4.8]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by PSO for the benefit of the holders of PSO Capital I's Preferred Securities [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.9]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997, between PSO and PSO Capital I [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.10].
4(c)	—	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee [Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 2000, File No. 0-343, Exhibits 4(c) and 4(d)]
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the PSO 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
SWEPCo‡		
3(a)	—	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 1997, File No. 1-3146, Exhibit 3.4].

Exhibit Number		Description
3(b)	—	By-Laws of SWEPCo (amended as of April 27, 2000) [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 2000, File No. 1-3146, Exhibit 3.3].
4(a)	—	Indenture, dated February 1, 1940, between SWEPCo and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.04; Registration Statement No. 2-61943, Exhibit 2.02; Registration Statement No. 2-66033, Exhibit 2.02; Registration Statement No. 2-71126, Exhibit 2.02; Registration Statement No. 2-77165, Exhibit 2.02; Form U-1 No. 70-7121, Exhibit 4; Form U-1 No. 70-7233, Exhibit 3; Form U-1 No. 70-7676, Exhibit 3; Form U-1 No. 70-7934, Exhibit 10; Form U-1 No. 72-8041, Exhibit 10(b); Form U-1 No. 70-8041, Exhibit 10(c); Form U-1 No. 70-8239, Exhibit 10(a)].
4(b)	—	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo: (1) Indenture, dated as of May 1, 1997, between SWEPCo and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of SWEPCo dated March 31, 1997, File No. 1-3146, Exhibits 4.11 and 4.12]. (2) Amended and Restated Trust Agreement of SWEPCo Capital I, dated as of May 1, 1997, among SWEPCo, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of SWEPCo dated March 31, 1997, File No. 1-3146, Exhibit 4.13]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by SWEPCo for the benefit of the holders of SWEPCo Capital I's Preferred Securities [Quarterly Report on Form 10-Q of SWEPCo dated March 31, 1997, File No. 1-3146, Exhibit 4.14]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997 between SWEPCo and SWEPCo Capital I [Quarterly Report on Form 10-Q of SWEPCo dated March 31, 1997, File No. 1-3146, Exhibits 4.15].
4(c)	—	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee [Annual Report on Form 10-K of SWEPCo for the fiscal year ended December 31, 2000, File No. 1-3146, Exhibits 4(c) and 4(d)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the SWEPCo 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
WTU‡		
3(a)	—	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation [Annual Report on Form 10-K of WTU for the fiscal year ended December 31, 1996, File No. 0-340, Exhibit 3.5].
3(b)	—	By-Laws of WTU (amended as of May 1, 2000) [Quarterly Report on Form 10-Q of WTU for the quarter ended March 31, 2000, File No. 0-340, Exhibit 3.4].

Exhibit Number		Description
4(a)	—	Indenture, dated August 1, 1943, between WTU and Harris Trust and Savings Bank and J. Bartolini, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.05; Registration Statement No. 2-63931, Exhibit 2.02; Registration Statement No. 2-74408, Exhibit 4.02; Form U-1 No. 70-6820, Exhibit 12; Form U-1 No. 70-6925, Exhibit 13; Registration Statement No. 2-98843, Exhibit 4(b); Form U-1 No. 70-7237, Exhibit 4; Form U-1 No. 70-7719, Exhibit 3; Form U-1 No. 70-7936, Exhibit 10; Form U-1 No. 70-8057, Exhibit 10; Form U-1 No. 70-8265, Exhibit 10; Form U-1 No. 70-8057, Exhibit 10(b); Form U-1 No. 70-8057, Exhibit 10(c)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the WTU 2001 Annual Report (for the fiscal year ended December 31, 2001) which are incorporated by reference in this filing.
*24	—	Power of Attorney.

‡Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM U-13-60

ANNUAL REPORT

FOR THE PERIOD

Beginning January 1, 2001 and Ending December 31, 2001

TO THE

U.S. SECURITIES AND EXCHANGE COMMISSION

OF

AMERICAN ELECTRIC POWER SERVICE CORPORATION
(Exact Name of Reporting Company)

A Subsidiary Service Company
("Mutual" or "Subsidiary")

Date of Incorporation December 17, 1937 If not Incorporated, Date of Organization ________.

State or Sovereign Power under which Incorporated or Organized New York

Location of Principal Executive Offices of Reporting Company Columbus, Ohio

Name, title, and address of officer to whom correspondence concerning this report should be addressed:

G. E. Laurey (Name)	Assistant Controller Regulated Accounting (Title)	1 Riverside Plaza Columbus, Ohio 43215 (Address)

Name of Principal Holding Company under which Reporting Company is organized:

AMERICAN ELECTRIC POWER COMPANY, INC.

INSTRUCTIONS FOR USE OF FORM U-13-60

1. **Time of Filing.** Rule 94 provides that on or before the first day of May in each calendar year, each mutual service company and each subsidiary service company as to which the Commission shall have made a favorable finding pursuant to Rule 88, and every service company whose application for approval or declaration pursuant to Rule 88 is pending shall file with the Commission an annual report on Form U-13-60 and in accordance with the Instructions for that form.

2. **Number of Copies.** Each annual report shall be filed in duplicate. The company should prepare and retain at least one extra copy for itself in case correspondence with reference to the report becomes necessary.

3. **Period Covered by Report.** The first report filed by any company shall cover the period from the date the Uniform System of Accounts was required to be made effective as to that company under Rules 82 and 93 to the end of that calendar year. Subsequent reports should cover a calendar year.

4. **Report Format.** Reports shall be submitted on the forms prepared by the Commission. If the space provided on any sheet of such form is inadequate, additional sheets may be inserted of the same size as a sheet of the form or folded to each size.

5. **Money Amounts Displayed.** All money amounts required to be shown in financial statements may be expressed in whole dollars, in thousands of dollars or in hundred thousands of dollars, as appropriate and subject to provisions of Regulation S-X (210.3-01(b)).

6. **Deficits Displayed.** Deficits and other like entries shall be indicated by the use of either brackets or a parenthesis with corresponding reference in footnotes. (Regulation S-X,210.3-01(c))

7. **Major Amendments or Corrections.** Any company desiring to amend or correct a major omission or error in a report after it has been filed with the Commission shall submit an amended report including only those pages, schedules, and entries that are to be amended or corrected. A cover letter shall be submitted requesting the Commission to incorporate the amended report changes and shall be signed by a duly authorized officer of the company.

8. **Definitions.** Definitions contained in Instruction 01-8 to the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, Public Utility Holding Company Act of 1935, as amended February 2, 1979 shall be applicable to words or terms used specifically within this Form U-13-60.

9. **Organization Chart.** The service company shall submit with each annual report a copy of its current organization chart.

10. **Methods of Allocation.** The service company shall submit with each annual report a listing of the currently effective methods of allocation being used by the service company and on file with the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935.

11. **Annual Statement of Compensation for Use of Capital Billed.** The service company shall submit with each annual report a copy of the annual statement supplied to each associate company in support of the amount of compensation for use of capital billed during the calendar year.

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE I - COMPARATIVE BALANCE SHEET

(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	ASSETS AND OTHER DEBITS	AS OF DECEMBER 31 2001	2000
	SERVICE COMPANY PROPERTY		
101-106	Service company property (Schedule II)	$ 359,889	$ 370,090
107	Construction work in progress (Schedule II)	128,566	26,381
	Total Property	488,455	396,471
108-111	Less: Accumulated provision for depreciation and amortization of service company property (Schedule III)	185,528	160,520
	Net Service Company Property	302,927	235,951
	INVESTMENTS		
123	Investments in associate companies (Schedule IV)	-	-
124	Other investments (Schedule IV)	102,663	89,027
	Total Investments	102,663	89,027
	CURRENT AND ACCRUED ASSETS		
131	Cash	2,271	2,266
134	Special deposits	75	76
135	Working funds	369	434
136	Temporary cash investments (Schedule IV)	-	-
141	Notes receivable	12	108
143	Accounts receivable	12,015	1,592
144	Accumulated provision for uncollectible accounts	-	-
145	Advances to Affiliates	22,382	-
146	Accounts receivable from associate companies (Schedule V)	194,052	259,695
152	Fuel stock expenses undistributed (Schedule VI)	-	-
154	Materials and supplies	-	-
163	Stores expense undistributed (Schedule VII)	-	-
165	Prepayments	3,562	1,663
174	Miscellaneous current and accrued assets (Schedule VIII)	-	9,402
	Total Current and Accrued Assets	234,738	275,236
	DEFERRED DEBITS		
181	Unamortized debt expense	4,150	3,416
184	Clearing accounts	718	370
186	Miscellaneous deferred debits (Schedule IX)	1,597	4,752
188	Research, development, or demonstration expenditures (Sch. X)	-	-
190	Accumulated deferred income taxes	185,586	73,105
	Total Deferred Debits	192,051	81,643
	TOTAL ASSETS AND OTHER DEBITS	$ 832,379	$ 681,857

Note: Unamortized Debt Expense includes unamortized loss on reacquired debt of $2,989,271 at December 31, 2001 and $3,416,309 at December 31, 2000.

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	LIABILITIES AND PROPRIETARY CAPITAL	AS OF DECEMBER 31 2001	2000
	PROPRIETARY CAPITAL		
201	Common stock issued (Schedule XI)	$ 1,450	$ 1,450
211	Miscellaneous paid-in-capital (Schedule XI)	(10,023)	-
215	Appropriated retained earnings (Schedule XI)	-	-
216	Unappropriated retained earnings (Schedule XI)		-
	Total Proprietary Capital	(8,573)	1,450
	LONG-TERM DEBT		
223	Advances from associate companies (Schedule XII)	1,100	1,100
224	Other long-term debt (Schedule XII)	56,000	58,000
225	Unamortized premium on long-term debt	-	-
226	Unamortized discount on long-term debt-debit	-	-
	Total Long-Term Debt	57,100	59,100
	OTHER NONCURRENT LIABILITIES		
227	Obligations under capital leases - Noncurrent	32,212	48,645
224.6	Other	64,925	114,187
	Total Other Noncurrent Liabilities	97,137	162,832
	CURRENT AND ACCRUED LIABILITIES		
228	Accumulated provision for pensions and benefits	-	-
231	Notes payable	-	-
232	Accounts payable	41,710	31,802
233	Notes payable to associate companies (Schedule XIII)	-	61,398
234	Accounts payable to associate companies (Schedule XIII)	85,969	78,101
236	Taxes accrued	22,485	48,695
237	Interest accrued	2,842	3,720
238	Dividends declared	-	-
241	Tax collections payable	677	3,982
242	Miscellaneous current and accrued liabilities (Schedule XIII)	401,316	147,224
243	Obligations under capital leases - Current	22,326	24,798
	Total Current and Accrued Liabilities	577,325	399,720
	DEFERRED CREDITS		
253	Other deferred credits	21,851	15,103
255	Accumulated deferred investment tax credits	851	902
	Total Deferred Credits	22,702	16,005
282	**ACCUMULATED DEFERRED INCOME TAXES**	86,688	42,750
	TOTAL LIABILITIES AND PROPRIETARY CAPITAL	$ 832,379	$ 681,857

Note: Long term debt includes $2,000,000 due within one year at December 31, 2001 and at December 31, 2000 (See note 7, Schedule XIV). "Other" Other noncurrent liabilities includes amounts due within one year of $732,814 at December 31, 2001 and $762,664 at December 31, 2000.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	8,169	15	-	-	8,184
304 Land and Land Rights	11,489	-	-	-	11,489
305 Structures and Improvements	183,173	1,239	-	-	184,412
306 Leasehold Improvements	6,810	342	-	-	7,152
307 Equipment (2)	19,541	-	-	(1,296)	18,245
308 Office Furniture and Equipment	13,205	2,333	-	1,296	16,834
309 Automobiles, Other Vehicles and Related Garage Equipment	194	-	-	-	194
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Service Company Property (3)	127,509	8,925	(24,589)	1,534	113,379
SUB-TOTALS	370,090	12,854	(24,589)	1,534	359,889
107 Non-Billable Construction Work in Progress (4)	26,381	102,185	-	-	128,566
TOTALS	$ 396,471	$ 115,039	$ (24,589)	$ 1,534	$ 488,455

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

FOOTNOTES

(1) *Provide an explanation of those changes considered material:*

None

(2) *Subaccounts are required for each class of equipment owned. The service company shall provide a listing by subaccount of equipment additions during the year and the balance at the close of the year:*

Subaccount Description	Additions	Balance At Close Of Year
Account 307 - Equipment:		
Data Processing Equipment	$ -	$ 14,286
Communications Equipment	-	3,959
TOTALS	$ -	$ 18,245

(3) *Describe Other Service Company Property:*

Account 311 includes leased assets at December 31, 2001 ($113,286,000) which have been capitalized in accordance with FASB Statement Nos. 13 and 71 and other owned assets at December 31, 2001 ($93,000).

(4) *Describe Non-Billable Construction Work in Progress*:

Capitalized Software	$ 127,270
General and Miscellaneous Equipment	832
Leasehold Improvements	74
Office Buildings-Owned	390
TOTALS	$ 128,566

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE III - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	4,682	1,915	-	-	6,597
304 Land and Land Rights	-	-	-	-	-
305 Structures and Improvements	79,386	9,118	6,671	-	95,175
306 Leasehold Improvements	3,496	402	-	-	3,898
307 Equipment	9,854	1,132	-	-	10,986
308 Office Furniture and Equipment	8,827	1,014	-	-	9,841
309 Automobiles, Other Vehicles and Related Garage Equipment	227	18	-	-	245
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Service Company Property	54,048	25,051	(20,342)	29	58,786
TOTALS	$ 160,520	$ 38,650	$ (13,671)	$ 29	$ 185,528

(1) Provide an explanation of those changes considered material:

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE IV - INVESTMENTS
(In Thousands)

Instructions: Complete the following schedule concerning investments.

Under Account 124 "Other Investments", state each investment separately, with description, including the name of issuing company, number of shares or principal amount, etc.

Under Account 136, "Temporary Cash Investments", list each investment separately.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 123 - Investment in Associate Companies		
Investment in Common Stock of Subs	$ -	$ -
SUB-TOTALS	-	-
Account 124 - Other Investments		
Cash Surrender Value of Life Insurance Policies (net of policy loans and accrued interest)	13,348	13,948
Umbrella Trust	74,267	72,053
Notes Receivable Constructive Marketing Program	96	-
COLI Tax and Interest	-	15,412
Other Investment - Nonassociated-Current	1,316	1,250
SUB-TOTALS	89,027	102,663
Account 136 - Temporary Cash Investments	-	-
TOTALS	$ 89,027	$ 102,663

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account Balances by Associate Company		
AEP C&I Company, LLC	$ -	$ 1
AEP Coal Co.	-	254
AEP Communications, Inc.	62	177
AEP Communications, LLC	5,101	846
AEP Credit, Inc.	233	198
AEP Delaware Investment Company II	11	14
AEP Delaware Investment Company III	-	5
AEP EmTech LLC	-	270
AEP Energy Services Gas Holding Company	660	48
AEP Energy Services Investments, Inc.	34	-
AEP Energy Services Limited	203	63
AEP Energy Services Ventures, Inc.	11	-
AEP Energy Services, Inc.	4,709	20,200
AEP Fiber Venture, LLC	4	293
AEP Gas Marketing LP	-	6
AEP Gas Power GP, LLC	-	2
AEP Gas Power System, LLC	-	50
AEP Generating Company	775	(335)
AEP Holdings I CV	-	2
AEP Investments, Inc.	149	198
AEP MEMCo LLC	-	2
AEP Ohio Commercial & Industrial Retail Company, LLC	-	1
AEP Ohio Retail Energy, LLC	-	10
AEP Power Marketing, Inc.	1	-
AEP Pro Serv, Inc.	2,208	1,767
AEP Pushan Power, LDC	49	15
AEP Resource Services LLC	10	1
AEP Resources International, Limited	-	6
AEP Resources Limited	383	-
AEP Resources, Inc.	2,231	2,541
AEP Retail Energy, LLC	22	6
AEP System Pool	(10,272)	9,628
AEP T & D Services, LLC	-	27

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES

(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
AEP Texas Commercial & Industrial Retail Limited Partnership	$ -	$ 15
AEP Texas Commercial & Industrial Retail GP, LLC	-	1
AEP Texas Retail GP, LLC	-	3
AEP Resources Australia Holdings Pty, Ltd	(29)	5
American Electric Power Company, Inc.	14,119	826
American Electric Power Service Corporation	494	-
Appalachian Power Company	45,259	25,919
Appalachian Power/Ohio Power Joint Account (Amos)	15,913	15,368
Appalachian Power/Ohio Power Joint Account (Sporn)	4,310	4,305
Blackhawk Coal Company	17	17
C3 Communications, Inc.	142	295
Cardinal Operating Company	611	851
Cedar Coal Co.	16	(14)
Central and South West Corporation	10,122	1,634
Central Appalachian Coal Company	2	4
Central Coal Company	3	5
Central Ohio Coal Company	1,045	133
Central Power and Light Company	13,111	15,594
Colomet, Inc.	29	17
Columbus Southern Power Company	28,758	32,106
Conesville Coal Preparation Company	333	190
Cook Coal Terminal	660	622
CSW Energy Services, Inc.	130	373
CSW Energy, Inc.	414	1,056
CSW International, Inc.	91	78
CSW Leasing, Inc.	281	7
Datapult Limited Partnership	-	30
Datapult, LLC	-	53
Dolet Hills Lignite Company, LLC	-	280
Energia de Mexicali S de R.L. de C.V.	-	1
EnerShop Inc.	21	14
Franklin Real Estate Company	(1)	-
Houston Pipe Line Company LP	-	515
HPL GP, LLC	-	13
HPL Resources Company LP	-	2

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Indiana Michigan Power Company	40,348	14,367
Indiana Michigan Power Company/Water Transportation Division	1,738	1,717
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	$ 2,080	$ 1,899
Industry and Energy Associates LLC	-	115
Jefferson Island Storage & Hub L. L. C.	12	3
Kentucky Power Company	9,739	2,965
Kingsport Power Company	1,248	801
LIG Liquids Company, L.L.C.	4	14
LIG Pipeline Company	-	2
LIG, Inc.	(2)	3
Louisiana Intrastate Gas Company, L.L.C	100	99
Mutual Energy CPU L.P.	-	1
Mutual Energy L.L.C.	-	1
Mutual Energy Service Company, L.L.C.	-	306
Mutual Energy SWEPCO L.P.	-	1
Mutual Energy WTU L.P.	-	1
Ohio Power Company	32,692	8,737
Price River Coal Company, Inc.	-	1
Public Service Company of Oklahoma	7,796	8,802
REP General Partner L.L.C.	-	94
REP Holdco Inc.	-	31
SEEBOARD plc	1,700	39
Simco, Inc.	2	-
Southern Appalachian Coal Company	3	3
Southern Ohio Coal Company	2,965	904
Southern Ohio Coal Company/Martinka	704	24
Southwestern Electric Power Company	9,553	10,344
SUBONE	-	8
Tuscaloosa Pipeline Company	(1)	(1)
West Texas Utilities Company	4,458	5,371
West Virginia Power Company	1	1
Wheeling Power Company	1,118	575
Windsor Coal Company	1,002	210
TOTALS	$ 217,609	$ 177,968

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
BY COMPANY:	
AEP C&I Company, LLC	$ 16
AEP Communications, LLC	161
AEP Credit, Inc.	1
AEP EmTech LLC	160
AEP Energy Services Ventures, Inc.	2
AEP Energy Services, Inc.	327
AEP Fiber Venture, LLC	25
AEP Generating Company	100
AEP Investments, Inc.	45
AEP Pro Serv, Inc.	310
AEP Resources, Inc.	4
AEP System Pool	7,982
American Electric Power Company, Inc.	329
Appalachian Power Company	232,556
Appalachian Power/Ohio Power Joint Account (Amos)	3,773
Appalachian Power/Ohio Power Joint Account (Sporn)	8
C3 Communications, Inc.	3
Cardinal Operating Company	2,466
Central and South West Corporation	4
Central Ohio Coal Company	11
Central Power and Light Company	19,908
Columbus Southern Power Company	130,297
Cook Coal Terminal	4
CSW Energy Services, Inc.	12
CSW Energy, Inc.	2
Datapult Limited Partnership	1
Datapult LLC	3
Houston Pipe Line Company LP	13
Indiana Michigan Power Company	294,071
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	25
Indiana Michigan Power Company/Water Transportation Division	4
Kentucky Power Company	57,429
Kingsport Power Company	45
LIG Liquids Company, LLC	1
Louisiana Intrastate Gas Company, LLC	3
Ohio Power Company	551,107
Public Liability	14
Public Service Company of Oklahoma	16,337

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
Southern Ohio Coal Company	59
Southwestern Electric Power Company	19,559
West Texas Utilities Company	6,533
Wheeling Power Company	52
Windsor Coal Company	2
TOTAL	$ 1,343,764

FOR:	
Interchange Power Pool & Transmission Agreements	$ 1,310,362
Insurance	520
Employee Benefit Plans	1,113
Membership Dues	2,399
Trustee Fees	107
Educational Programs	147
Outside Services	27,515
Postage & Shipping	227
Telephone Service	164
Office Supplies & Expense	827
Miscellaneous	383
TOTAL	$ 1,343,764

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For the Year Ended December 31, 2001

SCHEDULE VI - FUEL STOCK EXPENSES UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company. Under the section headed "Summary" listed below give an overall report of the fuel functions performed by the service company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 152 - Fuel Stock Expenses Undistributed			
Associate Companies			
Appalachian Power Company	$ 338	$ 376	$ 714
Appalachian Power/Ohio Power Joint Account (Amos)	161	196	357
Appalachian Power/Ohio Power Joint Account (Sporn)	74	87	161
Cardinal Operating Company	111	122	233
Central Power and Light Company	48	47	95
Columbus Southern Power Company	1,156	76	1,232
Indiana Michigan Power Company	163	171	334
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	265	312	577
Kentucky Power Company	106	126	232
Ohio Power Company	630	703	1,333
Public Service Company of Oklahoma	49	52	101
Southwestern Electric Power Company	128	164	292
West Texas Utilities Company	20	21	41
TOTALS	$ 3,249	$ 2,453	$ 5,702

Summary: The service company provides overall management of fuel supply and transportation procurement, as well as general administration.

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For the Year Ended December 31, 2001

SCHEDULE VII - STORES EXPENSE UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

ACCOUNT DESCRIPTION

Account 163 - Billable Stores Expense Undistributed	LABOR	EXPENSES	TOTAL
Associate Companies			
AEP Communications, LLC	$ -	$ 1	$ 1
AEP Energy Services, Inc.	8	(1)	7
AEP Pro Serv, Inc.	2	(2)	-
Appalachian Power Company	881	793	1,674
Appalachian Power/Ohio Power Joint Account (Amos)	47	40	87
Appalachian Power/Ohio Power Joint Account (Sporn)	26	21	47
Cardinal Operating Company	30	23	53
Central Power and Light Company	384	426	810
Central Ohio Coal Company	3	2	5
Columbus Southern Power Company	357	304	661
Conesville Coal Preparation Company	2	1	3
Cook Coal Terminal	9	8	17
Indiana Michigan Power Company	560	484	1,044
Indiana Michigan Power Company/Water Transporation Division	10	(2)	8
Indiana Michigan/AEP Generating Joint Account (Rockport)	36	29	65
Kentucky Power Company	175	159	334
Kingsport Power Company	11	7	18
Ohio Power Company	1,021	960	1,981
Public Service Company of Oklahoma	244	267	511
Southern Ohio Coal Company	22	18	40
Southwestern Electric Power Company	427	375	802
West Texas Utilities Company	265	218	483
Wheeling Power Company	12	7	19
Windsor Coal Company	6	4	10
TOTALS	$ 4,538	$ 4,142	$ 8,680

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE VIII - MISCELLANEOUS CURRENT AND ACCRUED ASSETS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 174 - Miscellaneous Current and Accrued Assets		
Liability accounts - debit balance	$ 1,676	$ -
Pension Plan	7,726	-
TOTALS	$ 9,402	$ -

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE IX - MISCELLANEOUS DEFERRED DEBITS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped by class showing the number of items in each class.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 186 - Miscellaneous Deferred Debits		
Regulatory Asset - Postemployment Benefits	$ 648	$ 324
Regulatory Asset - Postretirement Benefits	3,715	-
Regulatory Asset - Taxes	217	-
Unbilled Charges	172	1,273
TOTALS	$ 4,752	$ 1,597

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For the Year Ended December 31, 2001

SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES
(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION	AMOUNT
Account 188 - Billable Research, Development, or Demonstration Expenditures	
Transmission and Distribution	$ 1,210
Steam Power	1,408
Hydro	3
Nuclear	398
General Activities	3,916
TOTALS	$ 6,935

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For the Year Ended December 31, 2001

SCHEDULE XI - PROPRIETARY CAPITAL
(Dollars in thousands except per share amounts)

ACCOUNT NUMBER	CLASS OF STOCK	NUMBER OF SHARES AUTHORIZED	PAR OR STATED VALUE PER SHARE	OUTSTANDING CLOSE OF PERIOD NO. OF SHARES	OUTSTANDING CLOSE OF PERIOD TOTAL AMOUNT
Account 201	**Common Stock Issued**	20,000	$ 100	13,500	$ 1,350
Account 201	**Common Stock Issued**	10,000	$ 10	10,000	100
				TOTAL	$ 1,450

Instructions: Classify amounts in each account with brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.

ACCOUNT DESCRIPTION	AMOUNT
Account 211 - Miscellaneous Paid-In Capital	$ (10,023)
Account 215 - Appropriated Retained Earnings	-
TOTAL	$ (10,023)

Instructions: Give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentage, amount of dividend, date declared and date paid.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	NET INCOME OR (LOSS)	DIVIDENDS PAID	BALANCE AT CLOSE OF YEAR
Account 216 - Unappropriated Retained Earnings	$ -	$ -	$ -	$ -
TOTALS	$ -	$ -	$ -	$ -

SCHEDULE XII - LONG-TERM DEBT
(In Thousands)

Instructions: Advances from associate companies should be reported separately for advances on notes, and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation column. For Account 224 - Other long-term debt, provide the name of creditor company or organization, terms of the obligation, date of maturity, interest rate, and the amount authorized and outstanding.

NAME OF CREDITOR	TERM OF OBLIGATION CLASS & SERIES OF OBLIGATION	DATE OF MATURITY	INTEREST RATE	AMOUNT AUTHORIZED	BALANCE AT BEGINNING OF YEAR	ADDITIONS	DEDUCTIONS (1)	BALANCE AT CLOSE OF YEAR
Account 223 - Advances From Associate Companies		None	None	$ 1,100	$ 1,100	$ -	$ -	$ 1,100
Account 224 - Other Long-Term Debt:								
Connecticut Bank & Trust Company (as Trustee), Series E Mortgage Notes		12/15/08	9.600	70,000	48,000	-	2,000	46,000
Suntrust Bank		10/14/03	6.355	10,000	10,000	-	-	10,000
SUBTOTALS				80,000	58,000	-	2,000	56,000
TOTALS				$ 81,100	$ 59,100	$ -	$ 2,000	$ 57,100

(1) Give an explanation of deductions:
Loan Payments. See Note 7, Schedule XIV for further explanation of dates of maturity.

ANNUAL REPORT OF American Electric Power Service Corporation
For the Year Ended December 31, 2001
SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 233 - Notes Payable to Associate Companies		
	$ -	$ -
TOTALS	$ -	$ -
Account 234 - Accounts Payable to Associate Companies		
AEP Communications, LLC	$ 56	$ 56
AEP Energy Services Limited	13	13
AEP Energy Services, Inc.	2,479	319
AEP Fiber Venture, LLC	-	20
AEP Investments, Inc.	-	74
AEP Pro Serv, Inc.	116	201
AEP Resources Australia Pty., Ltd	48	-
AEP Resources, Inc.	-	73
AEP System Pool	553	-
American Electric Power Company, Inc.	3,766	3,846
Appalachian Power Company	3,193	(380)
Appalachian Power/Ohio Power Joint Account (Amos)	257	257
Appalachian Power/Ohio Power Joint Account (Sporn)	206	380
Cardinal Operating Company	150	31
Cedar Coal Co.	-	24
Central and South West Corporation	-	2,141
Central Power and Light Company	1,247	4,400
Columbus Southern Power Company	3,187	21,223
Datapult, LLC	791	-
Franklin Real Estate Company	115	-
Indiana Michigan Power Company	22,168	8,061
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	147	34
Kentucky Power Company	1,381	528
Kingsport Power Company	156	(7)
Louisiana Intrastate Gas Company, L.L.C.	-	57
LIG Chemical Company	-	5,804
LIG Liquids Company, L.L.C.	-	41
Ohio Power Company	35,421	29,353
Public Service Company of Oklahoma	717	4,947
Southwestern Electric Power Company	827	3,534
West Texas Utilities Company	937	906
Wheeling Power Company	167	16
Miscellaneous	3	17
TOTALS	$ 78,101	$ 85,969

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For the Year Ended December 31, 2001

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

	BEGINNING OF YEAR	CLOSE OF YEAR
Account 242 - Miscellaneous Current and Accrued Liabilities		
Control Cash Disbursements Accounts	$ 9,248	$ 9,919
Control Payroll Disbursement Accounts	1,101	3,962
Deferred Compensation Benefits	763	809
Employee Benefits	4,287	985
Incentive Pay	95,727	333,295
Real and Personal Property Taxes	644	142
Rent for Office Space at Market Square, Washington, D.C.	21	-
Rent on John E. Dolan Engineering Laboratory	791	747
Rent on Personal Property	-	195
Severance Pay	-	9,875
Vacation Pay	33,973	40,348
Workers' Compensation	669	552
Misc Current and Accrued Liabilities	-	487
TOTALS	$ 147,224	$ 401,316

SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

Instructions: The space below is provided for important notes regarding the financial statements or any account thereof. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.

1. Summary of Significant Accounting Policies

Organization

American Electric Power Service Corporation (the Company or AEPSC) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company provides certain managerial and professional services including administrative and engineering services to the affiliated companies in the American Electric Power (AEP) System and periodically to unaffiliated companies.

Merger

On June 15, 2000, AEP Co., Inc. merged with Central and South West Corporation (CSW) so that CSW became a wholly-owned subsidiary of AEP Co., Inc. On December 31, 2000, AEP Co., Inc. combined its investment in the net assets of CSW Services, Inc., a wholly-owned service company of CSW, with its investment in AEPSC. Since the merger of AEP and CSW was accounted for as a pooling of interests, the financial statements of AEPSC give retroactive effect to the combination of AEPSC and CSW Services, Inc. as if they had always been combined.

Regulation and Basis of Accounting

As a subsidiary of AEP Co., Inc., AEPSC is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act).

The Company's accounting conforms to the Uniform System of Accounts for Mutual and Subsidiary Service Companies prescribed by the SEC pursuant to the 1935 Act. As a cost-based rate-regulated entity, AEPSC's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), the financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions to match expenses and revenues in cost-based rates. Regulatory assets are expected to be recovered in future periods through billings to affiliated companies and regulatory liabilities are expected to reduce future billings. The Company has reviewed all the evidence currently available and concluded

that it continues to meet the requirements to apply SFAS 71. Among other things application of SFAS 71 requires that the Company's billing rates be cost-based regulated. In the event a portion of the Company's business were to no longer meet those requirements, net regulatory assets would have to be written off for that portion of the business and long-term assets would have to be tested for possible impairment.

Recognized regulatory assets and liabilities are comprised of the following:

December 31,
2001 2000
(in thousands)

SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

Regulatory Assets:		
Unamortized Loss on		
Reacquired Debt	$2,953	$3,375
Postretirement Benefits	324	648
Postemployment Benefits	-	3,715
Total Regulatory Assets	$3,277	$7,738

Regulatory Liabilities:		
Deferred Amounts Due to		
Affiliates for Income		
Tax Benefits	$12,756	$7,274
Deferred Investment		
Tax Credits	851	902
Total Regulatory Liabilities	$13,607	$8,176

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires in certain instances the use of management's estimates. Actual results could differ from those estimates.

Operating Revenues and Expenses

Services rendered to both affiliated and unaffiliated companies are provided at cost. The charges for services include no compensation for the use of equity capital, all of which is furnished by AEP Co., Inc. The costs of the services are determined on a direct charge basis to the extent practicable and on reasonable bases of proration for indirect costs.

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 billings, (that is, deferred taxes are not included in the cost of determining regulated billings for services), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71.

Investment Tax Credits

Investment tax credits have been accounted for under the flow-through method unless they have been deferred in accordance with regulatory treatment. Investment tax credits that have been deferred are being amortized over the life of the related investment.

Property

Property is stated at original cost. Land, structures and structural improvements are generally subject to first mortgage liens. Depreciation is provided on a straight-line basis over the estimated useful lives of the property. The annual composite depreciation rate was 7.8% for the year ended December 31, 2001 and 9.8% for the year ended December 31, 2000.

Investments

Investments include the cash surrender value of trust owned life insurance policies held under a grantor trust to provide funds for non-qualified deferred compensation plans sponsored by the Company.

Debt

With SEC staff approval, gains and losses on reacquired debt are deferred and amortized over the term of the replacement debt.

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

Comprehensive Income

2. Commitments and Contenginces

The Company is involved in a number of legal proceedings and claims. While management is unable to predict the outcome of litigation, any potential liability which may result therefrom would be recoverable from affiliated companies.

3. Benefit Plans

The Company participates in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension credits for the years ended December 31, 2001 and 2000 were $7.3 million and $5.7 million, respectively.

Postretirement Benefits Other Than Pensions are provided for retired employees for medical and death benefits under an AEP System plan. The Company's annual accrued cost was $20.2 million in 2001 and $18 million in 2000.

A defined contribution employee savings plan required that the Company make contributions to this plan totaling $18.8 million in 2001 and $10.8 million in 2000.

SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

4. Financial Instruments and Risk Management

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the short-term maturities of these instruments. The fair value of long-term debt, excluding advances from Parent Company, was $65 million and $70 million at December 31, 2001 and 2000, respectively. The balances are based on quoted market prices for similar issues and the current interest rates offered for debt of the same remaining maturities. The carrying amount for long-term debt, excluding advances from Parent Company, was $56 million at December 31, 2001, and $58 million at December 31, 2000.

The Company is subject to market risk as a result of changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has fixed and variable interest rates with terms from one day to eight years at December 31, 2001. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period.

5. Income Taxes

The details of income taxes are as follows:

	Year Ended December 31, 2001	2000
	(in thousands)	
Current (net)	$ 76,480	$ 70,819
Deferred (net)	(63,061)	(18,485)
Deferred Investment		
Tax Credits (net)	(51)	(51)
Total Income Taxes	$ 13,368	$ 52,283

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

	Year Ended December 31, 2001	2000
	(in thousands)	
Net Income	$ -	$ -
Income Taxes	13,368	52,283
Pre-Tax Income	$13,368	$52,283
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$ 4,678	$18,299
Increase (Decrease) in Income Tax Resulting from the Following Items:		
Corporate Owned Life Insurance	859	29,560
State and Local Income Taxes	7,000	2,891
Other	831	1,533
Total Income Taxes	$13,368	$52,283

SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

Effective Income Tax Rate N.M. N.M.

The following tables show the elements of the net deferred tax asset and the significant temporary differences:

	December 31, 2001	2000
	(in thousands)	
Deferred Tax Assets	$185,586	$ 73,105
Deferred Tax Liabilities	(86,688)	(42,750)
Net Deferred Tax Assets	$ 98,898	$ 30,355

Property Related Temporary Differences	$(21,224)	$(36,652)
Deferred and Accrued Compensation	108,886	20,785
Capitalized Software Cost	(44,654)	9,702
Accrued Pension Expense	19,832	8,283
Accrued Vacation Pay	12,643	7,978
Deferred State Income Taxes	6,725	907
Amounts Due to Affiliates For Future Income Taxes	2,122	2,239
All Other (net)	14,568	17,113
Net Deferred Tax Assets	$ 98,898	$ 30,355

The Company 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 utilized to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. The AEP System has received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

COLI Litigation – On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP System companies in its suit against the United States over deductibility of interest claimed in their consolidated federal income tax return related to a corporate owned life insurance (COLI) program. The suit was filed to resolve the IRS' assertion that interest deductions for the COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI Interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in investments pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, expenses were increased by $38 million in 2000, which were billed to the affiliated companies. The Company has filed an appeal of the U.S. District Court's decision with the U.S. Court of appeals for the 6th

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SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

6. Leases

Leases of structures, improvements, office furniture and miscellaneous equipment are for periods of up to 30 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

The components of lease rental costs are as follows:

	Year Ended December 31, 2001	2000
	(in thousands)	
Lease Payments on		
Operating Leases	$10,485	$ 8,419
Amortization of Capital Leases	25,044	27,402
Interest on Capital Leases	3,996	6,748
Total Lease Rental Costs	$39,525	$42,569

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

	December 31, 2001	2000
	(in thousands)	
Property Under Capital Leases:		
Structures and Improvements	$ 11,754	$ 11,754
Office Furniture and Miscellaneous Equipment	101,532	115,671
Total Property Under Capital Leases	113,286	127,425
Accumulated Amortization	58,748	53,982
Net Property Under Capital Leases	$ 54,538	$ 73,443
Obligations Under Capital Leases*:		
Noncurrent Liability	$32,212	$48,645
Liability Due Within One Year	22,326	24,798
Total Obligations Under Capital leases	$54,538	$73,443

* Represents the present value of future minimum lease payments.

Property under operating leases and related obligations are not included in the Balance Sheets.

Future minimum lease payments for capital leases consisted of the following at December 31, 2001:

	Capital Leases (in thousands)	Operating Leases
2002	$23,423	$12,902
2003	16,271	12,483
2004	8,207	7,524
2005	3,170	3,159
2006	1,787	2,647
Later Years	14,558	1,215
Total Future Minimum Lease Rentals	67,416	39,930
Less Estimated Interest Element	12,878	-
Estimated Present Value of Future Minimum Lease Rentals	$54,538	$39,930

7. Long-Term Debt

Long-term debt was outstanding as follows:

	Interest Rate	December 31, 2001 (in thousands)	2000
Notes Payable to Banks:			
Due October 2003	6.355%	$10,000	$10,000
Mortgage Notes:			
Series E (a)	9.60%	46,000	48,000
Advances from Parent Company	(b)	1,100	1,100
		57,100	59,100
Less Portion Due Within One Year		2,000	2,000
Total		$55,100	$57,100

(a) Due in annual installments of $2,000,000 until 2007 and the balance in December 2008.

(b) The advances from parent company are non-interest bearing and have no due date.

Long-term debt outstanding at December 31, 2001 is payable as follows:

	Principal Amount (in thousands)
2002	$ 2,000
2003	12,000
2004	2,000
2005	2,000
2006	2,000
Later Years	37,100
Total	$57,100

SCHEDULE XIV - NOTES TO FINANCIAL STATEMENTS

8. Segment Information

The Company has one reportable segment. The Company provides certain managerial and professional services including administrative and engineering services. For the years ended December 31, 2001 and 2000, all of the Company's revenues are derived from managerial and professional services including administrative and engineering services in the United States.

9. Merger and Acquisition Costs

The cost of services performed by AEPSC related to mergers and acquisitions are charged to AEP Co., Inc. or its regulated affiliates or nonregulated affiliates as appropriate. Such costs would be charged to AEP's regulated utilities only if the merger or acquisition pertained to them. Merger costs of AEP Co., Inc. with CSW that were allowed to be recovered from rate-payers were recorded on the electric utility affiliates' books.

10. Short Term Debt Borrowings

In June 2000 the AEP System established a Money Pool, to coordinate short-term borrowings for certain subsidiaries, primarily the domestic electric utility operating companies. The operation of the Money Pool is designed to match on a daily basis the available cash and borrowing requirements of the participants, thereby minimizing the need for short-term borrowings from external sources and increasing the interest income for participants with available cash. Participants with excess cash loan funds to the Money Pool reducing the amount of external funds AEP needs to borrow to meet the short-term cash requirements of other participants whose short-term cash requirements are met through advances from the Money Pool. AEP borrows the funds on a daily basis, when necessary, to meet the net cash requirements of the Money Pool participants. A weighted average daily interest rate which is calculated based on the outstanding short-term debt borrowings made by AEP is applied to each Money Pool participant's daily outstanding investment or debt position to determine interest income or interest expense. The Money Pool participants include interest income in nonoperating income and interest expense in interest charges. As a result of becoming a Money Pool participant, AEPSC retired its short-term debt. At December 31, 2001 AEPSC is a net lender and at December 31, 2000 a net borrower from the Money Pool and reports its receivable position as Advances to Affiliates and it debt position as Advances from Affiliates on the balance sheets.

AEPSC earned interest income of $873,000 for amounts advanced to the AEP Money Pool for the year 2001.

AEPSC incurred interest expense of $3,656,000 and $4,748,000 for amounts borrowed from the AEP Money Pool for the years 2001 and 2000.

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SCHEDULE XV - COMPARATIVE INCOME STATEMENT
(In Thousands)

ACCOUNT	DESCRIPTION	CURRENT YEAR	PRIOR YEAR
	INCOME		
454	Rents from electric properties - NAC	$ 5	$ -
456	Other electric revenues	1	138
457	Services rendered to associate companies	1,274,210	1,200,660
458	Services rendered to non associate companies	14,956	4,381
419	Interest income - other	878	96
421	Miscellaneous income or loss	261	4,660
447	Impact studies	(2,888)	322
	TOTAL INCOME	1,287,423	1,210,257
	EXPENSES		
500-559	Power production	316,672	184,585
560-579	Transmission	29,859	22,329
580-599	Distribution	49,562	28,647
780-860	Trading	3,390	-
901-903	Customer accounts expense	151,292	111,402
905	Miscellaneous customer accounts	2,833	907
906-917	Customer service & information	13,866	26,998
920	Salaries and wages	340,291	322,187
921	Office supplies and expenses	98,907	67,327
922	Administrative expense transferred - credit	(303,697)	(164,947)
923	Outside services employed	93,937	90,681
924	Property insurance	141	227
925	Injuries and damages	8,043	8,527
926	Employee pensions and benefits	87,272	74,505
928	Regulatory commission expense	230	12,634
930.1	General advertising expenses	2,796	3,034
930.2	Miscellaneous general expenses	6,091	17,865
931	Rents	89,882	71,198
935	Maintenance of structures and equipment	26,161	14,269
403-405	Depreciation and amortization expense	13,598	18,115
408	Taxes other than income taxes	42,909	34,353
409	Income taxes	76,481	70,819
410	Provision for deferred income taxes	124,713	35,148
411	Provision for deferred income taxes - credit	(187,825)	(53,683)
416	Expense - sports lighting	897	1,883
417	Administrative - business venture	638	1,456
418	Non-Operating rental income	69	-
426.1	Donations	5,106	1,949
426.3 - 426.5	Other deductions	6,404	3,613
427	Interest on long-term debt	4,979	5,853
428	Amortization of debt discount and expense	427	427
430	Interest on debt to associate companies	3,656	7,095
431	Other interest expense	382	12,501
432	Borrowed funds - construction - credit	(3,691)	-
	TOTAL EXPENSE - INCOME STATEMENT	1,106,271	1,031,904
	COST OF SERVICE - BALANCE SHEET		
107	Construction work in progress	130,111	128,957
108	Retirement work in progress	4,883	4,905
120	Nuclear fuel	-	1
124	Investments	(335)	-
151	Fuel stock	3,585	1,978
152	Fuel stock expense undistributed	5,685	4,425
163	Stores expense undistributed	8,679	12,151
182	Regulatory Assets	4,602	1,863
183	Preliminary survey and investigation charges	-	747
184	Clearing accounts	2,397	2,687
186	Miscellaneous deferred debits	14,610	18,650
188	Research, development, or demonstration expenses	6,935	1,989
	TOTAL COST OF SERVICE - BALANCE SHEET	181,152	178,353
	NET INCOME OR (LOSS)	$ -	$ -

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ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457 .1	INDIRECT COSTS CHARGED 457 .2	COMPENSATION FOR USE OF CAPITAL 457 .3	TOTAL AMOUNT BILLED
AEP C&I Company, LLC	$ 14	$ 3	$ -	$ 17
AEP Coal Company	167	144	-	311
AEP Communications, Inc.	47	7	-	54
AEP Communications, LLC	12,736	2,552	(32)	15,256
AEP Credit, Inc.	1,616	175	(1)	1,790
AEP Delaware Investment Company	1	-	-	1
AEP Delaware Investment Company II	20	7	-	27
AEP EmTech LLC	1,022	322	-	1,344
AEP Energy Management, LLC	6	-	(1)	5
AEP Energy Services Gas Holding Company	413	90	(2)	501
AEP Energy Services Gas Holdings II LLC	5	3	-	8
AEP Energy Services, Inc.	76,166	7,199	(28)	83,337
AEP Energy Services Limited	826	100	(3)	923
AEP Energy Services Ventures, Inc.	1	-	-	1
AEP Fiber Venture, LLC	47	1,239	-	1,286
AEP Gas Marketing LP	12	3	-	15
AEP Gas Power GP, LLC	8	3	-	11
AEP Gas Power System, LLC	274	41	-	315
AEP Generating Company	315	92	(2)	405
AEP Holdings I CV	2	1	-	3
AEP Investments, Inc.	174	46	(1)	219
AEP Memco LLC	1	1	-	2
AEP Ohio Commercial & Industrial Retail Company, LLC	6	2	-	8
AEP Ohio Retail Energy, LLC	10	2	-	12
AEP Power Marketing, Inc.	-	(1)	-	(1)
AEP Pro Serv, Inc.	20,965	2,183	(9)	23,139
AEP Pushan Power, LDC	222	37	-	259
AEP Resources International, Limited	15	3	-	18
AEP Resources Limited	191	36	-	227
AEP Resources, Inc.	8,140	1,725	(11)	9,854
AEP Resources Services LLC	3	1	-	4
AEP Retail Energy, LLC	36	7	-	43
AEP System Pool	200,753	10,597	-	211,350
AEP T&D Services, LLC	122	17	-	139
AEP Texas Commercial & Industrial Retail Limited Partnership	18	3	-	21
AEP Texas Commercial & Industrial Retail GP, LLC	3	1	-	4
AEP Texas Retail GP, LLC	2	1	-	3
American Electric Power Company, Inc.	10,774	2,572	(37)	13,309
Appalachian Power Company	118,428	23,145	(140)	141,433
Appalachian Power/Ohio Power Joint Account (Amos)	18,230	2,339	(16)	20,553
Appalachian Power/Ohio Power Joint Account (Sporn)	6,423	749	(4)	7,168
Blackhawk Coal Company	48	13	-	61
C3 Communications, Inc.	1,000	367	(1)	1,366
Cardinal Operating Company	8,445	1,127	(5)	9,567
Cedar Coal Company	25	9	-	34
Central and South West Corporation	1,571	2,858	(109)	4,320
Central Appalachian Coal Company	4	2	-	6
Central Coal Company	11	4	-	15
Central Ohio Coal Company	614	178	4	796
Central Power and Light Company	95,583	18,594	(98)	114,079
Colomet, Inc.	223	52	-	275
Columbus Southern Power Company	72,722	13,804	(83)	86,443
Conesville Coal Preparation Company	570	181	(1)	750
CSW Energy, Inc.	5,850	607	(2)	6,455
CSW Energy Services, Inc.	2,152	331	(1)	2,482
CSW International, Inc.	1,108	105	1	1,214
CSW Leasing, Inc.	31	7	-	38
Datapult LLC	1	168	-	169

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ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457.1	INDIRECT COSTS CHARGED 457.2	COMPENSATION FOR USE OF CAPITAL 457.3	TOTAL AMOUNT BILLED
Datapult Limited Partnership	415	182	-	597
Dolet Hills Lignite Company, LLC	448	283	-	731
Energia de Mexicali, S de R.L. de C.V.	1	3	-	4
EnerShop Inc.	62	12	-	74
Franklin Real Estate Company	4	1	-	5
HPL GP, LLC	9	4	-	13
HPL Resources Company LP	2	-	-	2
Houston Pipeline Company LP	7,195	479	-	7,674
Indiana Franklin Reality, Inc.	1	-	-	1
Indiana Michigan Power Company	87,520	16,666	(104)	104,082
Indiana Michigan Power/Water Transportation	1,343	335	(1)	1,677
Indiana Michigan/AEP Generating Joint Account (Rockport)	6,884	1,148	(6)	8,026
Industry and Energy Associates LLC	147	18	-	165
Jefferson Island Storage & Hub LLC	56	10	-	66
Kentucky Power Company	26,177	5,010	(30)	31,157
Kingsport Power Company	2,931	619	(4)	3,546
LIG Chemical Company	2	-	-	2
LIG Liquids Company LLC	43	8	-	51
LIG Pipeline Company	8	1	-	9
LIG, Inc.	6	1	-	7
Louisiana Intrastate Gas Company, LLC	207	36	-	243
MidTexas Pipeline Company	22	2	-	24
Mutual Energy CPU L.P.	1	-	-	1
Mutual Energy L.L.C.	6	1	-	7
Mutual Energy Service Company, L.L.C.	1,547	265	-	1,812
Ohio Power Company	120,995	22,312	(144)	143,163
Ohio Power/Cook Coal Terminal	881	182	(1)	1,062
Public Service Company of Oklahoma	55,731	11,356	(57)	67,030
Rep General Partner L.L.C.	70	25	-	95
Rep Holdco Inc.	28	3	-	31
SEEBOARD	86	5	-	91
Simco, Inc.	5	-	-	5
Southern Appalachian Coal Company	5	1	-	6
Southern Ohio Coal Company - Martinka	8	3	-	11
Southern Ohio Coal Company - Meigs	2,387	607	15	3,009
Southwestern Electric Power Company	73,960	13,895	(71)	87,784
West Texas Utilites Company	36,922	7,300	(32)	44,190
West Virginia Power Company	1	-	-	1
Wheeling Power Company	3,056	668	(4)	3,720
Windsor Coal Company	696	197	6	899
Unbilled Revenues	1,693	-	-	1,693
TOTALS	$ 1,099,733	$ 175,492	$ (1,015)	$ 1,274,210

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ANALYSIS OF BILLING - NONASSOCIATE COMPANIES - ACCOUNT 458
(In Thousands)

NAME OF NONASSOCIATE COMPANY	DIRECT COST CHARGED 458.1	INDIRECT COST CHARGED 458.2	COMPENSATION FOR USE OF CAPITAL 458.3	TOTAL COST	EXCESS OR DEFICIENCY 458.4	TOTAL AMOUNT BILLED
Bridgeco	$ 274	$ 88	$ -	$ 362	$ -	$ 362
Cinergy	4,399	559	-	4,958	-	4,958
East Central Area Reliability	731	446	-	1,177	-	1,177
Indiana Kentucky Electric Corporation	811	113	-	924	-	924
Ohio Valley Electric Company	6,965	570	-	7,535	-	7,535
TOTALS	$ 13,180	$ 1,776	$ -	$ 14,956	$ -	$ 14,956

Instruction: Provide a brief description of the services rendered to each nonassociate company:
Engineering, Computer and Environmental Laboratory services.

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SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES

(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - INCOME STATEMENT										
454	Rents from electric properties - NAC	$ (5)	$ -	$ (5)	$ -	$ -	$ -	$ (5)	$ -	$ (5)
456	Other electric revenues	(1)	-	(1)	-	-	-	(1)	-	(1)
421	Miscellaneous income or loss	(236)	(25)	(261)	-	-	-	(236)	(25)	(261)
447	Impact studies	2,888	-	2,888	-	-	-	2,888	-	2,888
458	Services rendered to non associate companies	-	-	-	-	-	-	-	-	-
500-559	Power production	303,959	11,815	315,774	873	25	898	304,832	11,840	316,672
560-579	Transmission	22,953	5,119	28,072	1,141	646	1,787	24,094	5,765	29,859
580-599	Distribution	42,224	7,338	49,562	-	-	-	42,224	7,338	49,562
780-860	Trading	3,338	52	3,390	-	-	-	3,338	52	3,390
901-903	Customer accounts expense	130,618	20,667	151,285	6	1	7	130,624	20,668	151,292
905	Customer assistance	2,512	321	2,833	-	-	-	2,512	321	2,833
906-917	Customer service & information	12,558	1,308	13,866	-	-	-	12,558	1,308	13,866
920	Salaries and wages	310,175	28,677	338,852	1,294	145	1,439	311,469	28,822	340,291
921	Office supplies and expenses	84,752	13,946	98,698	186	23	209	84,938	13,969	98,907
922	Administrative expense transferred - credit	(176,742)	(126,955)	(303,697)	-	-	-	(176,742)	(126,955)	(303,697)
923	Outside service employed	76,980	6,350	83,330	9,674	933	10,607	86,654	7,283	93,937
924	Property insurance	140	1	141	-	-	-	140	1	141
925	Injuries and damages	7,184	858	8,042	-	1	1	7,184	859	8,043
926	Employee pensions and benefits	85,043	2,229	87,272	-	-	-	85,043	2,229	87,272
928	Regulatory commission expense	164	66	230	-	-	-	164	66	230
930.1	General advertising expense	2,564	232	2,796	-	-	-	2,564	232	2,796
930.2	Miscellaneous general expense	5,452	638	6,090	1	-	1	5,453	638	6,091
931	Rents	87,476	2,406	89,882	-	-	-	87,476	2,406	89,882
935	Maintenance of structures and equipment	25,200	961	26,161	-	-	-	25,200	961	26,161
403-405	Depreciation and amortization expense	13,598	-	13,598	-	-	-	13,598	-	13,598
408	Taxes other than income taxes	42,735	174	42,909	-	-	-	42,735	174	42,909
409	Income taxes	76,296	185	76,481	-	-	-	76,296	185	76,481
410	Provision for deferred income taxes	124,713	-	124,713	-	-	-	124,713	-	124,713
411	Provision for deferred income taxes - credit	(187,825)	-	(187,825)	-	-	-	(187,825)	-	(187,825)
416	Sports lighting	762	135	897	-	-	-	762	135	897
417	Administrative - business venture	511	118	629	6	3	9	517	121	638
418	Non-Operating rental income	66	3	69	-	-	-	66	3	69
419	Interest income - other	(878)	-	(878)	-	-	-	(878)	-	(878)
426.1	Donations	4,595	511	5,106	-	-	-	4,595	511	5,106
426.3-426.5	Other deductions	5,875	529	6,404	-	-	-	5,875	529	6,404
427	Interest on long-term debt	4,979	-	4,979	-	-	-	4,979	-	4,979
428	Amortization of debt discount and expense	427	-	427	-	-	-	427	-	427
430	Interest on debt to associate companies	3,647	9	3,656	-	-	-	3,647	9	3,656
431	Other interest expense	424	(42)	382	-	-	-	424	(42)	382
432	Borrowed funds - construction - credit	(3,691)	-	(3,691)	-	-	-	(3,691)	-	(3,691)
TOTAL COST OF SERVICE - INCOME STATEMENT		1,115,430	(22,374)	1,093,056	13,181	1,777	14,958	$1,128,611	(20,597)	$1,108,014

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SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES

(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - BALANCE SHEET										
107	Construction work in progress	115,034	15,077	130,111	-	-	-	115,034	15,077	130,111
108	Retirement work in progress	2,983	1,900	4,883	-	-	-	2,983	1,900	4,883
120	Nuclear fuel	-	-	-	-	-	-	-	-	-
124	Investments	(164)	(171)	(335)	-	-	-	(164)	(171)	(335)
151	Fuel stock	2,511	1,074	3,585	-	-	-	2,511	1,074	3,585
152	Fuel stock expense undistributed	4,480	1,205	5,685	-	-	-	4,480	1,205	5,685
163	Stores expense undistributed	7,711	968	8,679	-	-	-	7,711	968	8,679
182	Regulatory assets	4,250	352	4,602	-	-	-	4,250	352	4,602
183	Preliminary survey & investigation charges	-	-	-	-	-	-	-	-	-
184	Clearing accounts	2,166	231	2,397	-	-	-	2,166	231	2,397
186	Miscellaneous deferred debits	9,766	4,844	14,610	-	-	-	9,766	4,844	14,610
188	Research, development, or demonstration expense	5,533	1,402	6,935	-	-	-	5,533	1,402	6,935
TOTAL COST OF SERVICE - BALANCE SHEET		154,270	26,882	181,152	-	-	-	154,270	26,882	181,152
TOTAL COST OF SERVICE		$ 1,269,700	$ 4,508	$ 1,274,208	$ 13,181	$ 1,777	$ 14,958	$ 1,282,881	$ 6,285	$ 1,289,166

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION

(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

ACCOUNT	DESCRIPTION OF ITEMS	TOTAL AMOUNT	DEPARTMENT OR SERVICE FUNCTION: OVERHEAD	ACCOUNTING	ACCOUNTING & FIN. SVCS.	AEP PROSERV	AUDIT SERVICES	CORPORATE COMMUN.	CORPORATE DEVELOP.	CORPORATE PLAN & BUDG.	CORPORATE SUPPLY CHAIN
454	Rents from Electric Properties - NAC	$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other Electric Revenues	(1)	-	-	-	-	-	-	-	-	-
419	Interest Income - Other	(878)	-	-	-	-	-	-	-	-	-
421	Miscellaneous Income or Loss	(261)	(20)	(1)	-	-	-	-	-	-	-
447	Impact Studies	2,888	-	-	-	-	-	-	-	-	-
500-559	Power Production	316,672	11,824	467	108	437	-	4	115	586	-
560-579	Transmission	29,859	5,604	-	-	-	48	-	10	73	-
580-599	Distribution	49,562	7,328	-	-	-	13	-	56	2	1
780-860	Trading	3,390	52	-	-	12	-	-	-	-	-
901-903	Customer Accounts Expense	151,292	20,294	2,855	-	-	7	-	72	3	-
905	Misc. Customer Accounts/Customer Assistance	2,833	321	1	-	-	25	-	2	-	-
906-917	Customer Service & Information	13,866	1,373	3	-	-	2	2	38	-	-
920	Salaries and Wages	340,291	24,675	21,915	578	1,458	5,417	7,542	17,210	6,995	3,078
921	Office Supplies and Expenses	98,907	8,821	3,167	15	236	727	2,483	1,954	944	1,574
922	Administrative Expense Transferred - Credit	(303,697)	5	(402,915)	99	87	706	1,298	3,368	633	549
923	Outside Service Employed	93,937	5,346	2,719	-	3	366	841	738	272	130
924	Property Insurance	141	1	-	-	-	-	-	-	-	-
925	Injuries and Damages	8,043	704	-	-	-	-	-	-	-	-
926	Employee Pensions and Benefits	87,272	1,620	90	-	-	8	57	63	13	8
928	Regulatory Commission Expense	230	66	93	-	-	-	-	-	-	-
930.1	General Advertising Expense	2,796	225	1	-	-	-	1,288	26	1	-
930.2	Miscellaneous General Expense	6,091	602	20	-	-	3	6	248	50	10
931	Rents	89,882	288	286	(1)	32	(1)	32	(2)	(2)	(2)
935	Maintenance of Structures and Equipment	26,161	470	(1)	-	14	-	-	-	-	-
403-405	Depreciation and Amortization Expense	13,598	-	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	42,909	(3)	385	14	(1)	56	124	477	132	53
409	Income Taxes	76,481	-	-	-	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	124,713	-	-	-	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	(187,825)	-	-	-	-	-	-	-	-	-
416	Cost and Expense of Merchandising	897	135	42	-	-	-	-	-	-	-
417	Administrative - Business Venture	638	121	-	-	2	-	2	29	-	-
418	Non-Operating Rental Income	69	3	-	-	-	-	-	-	-	-
426.1	Donations	5,106	446	1	-	-	2	2	-	-	-
426.3-426.5	Other Deductions	6,404	514	66	-	(2)	39	146	2	1	1
427	Interest on Long Term Debt	4,979	-	-	-	-	-	-	-	-	-
428	Amortization on Long Term Debt	427	-	-	-	-	-	-	-	-	-
430	Interest On Debt to Associate Companies	3,656	-	-	-	-	-	-	-	-	-
431	Other Interest Expense	382	2	-	-	-	-	-	-	-	-
432	Borrowed Funds - Construction - Credit	(3,691)	-	-	-	-	-	-	-	-	-
107	Construction Work in Progress	130,111	9,923	1,555	13	326	-	5	426	99	-
108	Retirement Work in Progress	4,883	341	345	-	16	-	-	-	-	-
120	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
124	Investments	(335)	(149)	-	-	-	-	-	1	-	-
151	Fuel Stock	3,585	904	233	-	-	-	-	-	-	-
152	Fuel Stock Expense Undistributed	5,685	928	652	-	8	-	3	-	-	-
163	Stores Expense Undistributed	8,679	565	362	-	-	-	-	-	-	(323)
182	Regulatory Assets	4,602	227	167	-	-	10	15	1	499	-
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-	-	-
184	Clearing Accounts	2,397	119	54	-	-	(1)	-	-	-	-
186	Miscellaneous Deferred Debits	14,610	4,028	11	-	1	-	62	1	21	-
188	Research, Development, or Demonstration Exp.	6,935	1,068	-	-	6	40	18	47	2	9
	TOTAL COST OF SERVICE	$ 1,289,166	$ 108,771	$ (367,427)	$ 826	$ 2,635	$ 7,467	$ 13,930	$ 24,882	$ 10,324	$ 5,088

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION									
ACCOUNT	DESCRIPTION OF ITEMS	CUSTOMER OPERATIONS	ENERGY DELIVERY	ENERGY DEL. SUPPORT	ENERGY DISTRIBUTION	ENERGY SERVICES	ENERGY TRANSMISSION	ENGINEER. SERVICES	ENVIRON. AFFAIRS	ENVIRON. SERVICES	EXECUTIVE GROUP
454	Rents from Electric Properties - NAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other Electric Revenues	-	-	-	-	-	-	1	-	-	-
419	Interest Income - Other	-	-	-	-	-	-	-	-	-	-
421	Miscellaneous Income or Loss	(2)	(1)	(12)	(1)	(1)	(2)	(1)	-	-	-
447	Impact Studies	-	-	-	-	2,888	-	-	-	-	-
500-559	Power Production	11	4,669	79	9	200,373	152	20,373	278	5,057	2,099
560-579	Transmission	7	7,398	541	193	40	10,905	6	-	659	553
580-599	Distribution	3,378	1,319	4,245	21,898	2	380	2	-	1,442	901
780-860	Trading	-	-	246	-	-	-	-	-	4	-
901-903	Customer Accounts Expense	118,905	15	24	116	50	20	-	-	-	5,454
905	Misc. Customer Accounts/Customer Assistance	1,411	94	-	1	-	-	-	-	-	7
906-917	Customer Service & Information	6,458	94	5	25	1	6	4	-	-	122
920	Salaries and Wages	4,485	1,719	9,250	950	63,784	1,699	9,955	2,597	806	10,419
921	Office Supplies and Expenses	3,914	1,398	12,114	1,094	3,107	1,784	1,162	439	189	5,935
922	Administrative Expense Transferred - Credit	22,301	13,452	3,175	6,351	4,898	6,536	2,928	60	772	5,671
923	Outside Service Employed	79	497	424	3	2,070	8	10,206	41	225	6,725
924	Property Insurance	-	-	-	-	-	-	-	-	-	-
925	Injuries and Damages	16	-	1	389	-	6	-	-	-	2
926	Employee Pensions and Benefits	116	31	50	35	60	42	49	-	19	110
928	Regulatory Commission Expense	-	64	-	-	-	-	-	-	-	6
930.1	General Advertising Expense	9	-	1	6	1	28	-	-	-	96
930.2	Miscellaneous General Expense	107	18	133	16	8	994	38	3	8	926
931	Rents	152	(1)	2,141	9	1,539	22	(1)	-	(5)	71
935	Maintenance of Structures and Equipment	1	-	4,234	-	118	-	1	-	-	10
403-405	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	1,059	149	365	272	1,521	623	767	44	157	149
409	Income Taxes	-	-	-	-	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	-	-	-	-	-
416	Cost and Expense of Merchandising	718	-	-	-	-	-	-	-	-	-
417	Administrative - Business Venture	-	-	-	-	8	-	4	-	294	-
418	Non-Operating Rental Income	-	-	-	-	2	-	-	-	-	-
426.1	Donations	35	68	-	1	-	1	-	127	-	39
426.3-426.5	Other Deductions	3	74	-	1	(26)	15	181	445	(1)	303
427	Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-
428	Amortization on Long Term Debt	-	-	-	-	-	-	-	-	-	-
430	Interest On Debt to Associate Companies	-	-	-	-	-	-	-	-	-	-
431	Other Interest Expense	-	-	-	-	-	-	-	-	-	-
432	Borrowed Funds - Construction - Credit	-	-	-	-	-	-	-	-	-	-
107	Construction Work in Progress	2,090	231	1,947	4,865	987	40,402	8,785	-	335	1,297
108	Retirement Work in Progress	1	-	11	257	-	167	135	-	6	-
120	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
124	Investments	-	-	-	-	-	-	-	-	3	-
151	Fuel Stock	-	-	-	-	57	-	249	-	133	-
152	Fuel Stock Expense Undistributed	-	-	-	-	2,040	-	209	-	22	-
163	Stores Expense Undistributed	-	14	5,294	-	-	2	3	-	-	33
182	Regulatory Assets	312	82	1	-	-	-	-	-	-	-
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-	-	-
184	Clearing Accounts	-	-	1	-	-	2	-	-	-	9
186	Miscellaneous Deferred Debits	-	5,700	36	125	18	2,128	35	8	6	-
188	Research, Development, or Demonstration Exp.	-	-	5	5	-	28	108	10	55	5,334
	TOTAL COST OF SERVICE	$ 165,566	$ 37,084	$ 44,311	$ 36,620	$ 283,545	$ 65,948	$ 55,199	$ 4,052	$ 10,186	$ 46,271

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION

(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION								
ACCOUNT	DESCRIPTION OF ITEMS	FOSSIL & HYDRO OPER.	GENERAL SERVICES	GOVERNMENTAL AFFAIRS	HUMAN RESOURCES	INFORMATION TECHNOLOGY	LEGAL	MAINT SVCS & REG SVC ORG	MAJOR PROJECTS	MARKET & BUS. DEV.	MINING OPERATIONS
454	Rents from Electric Properties - NAC	$ -	$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-
419	Interest Income - Other	-	-	-	-	-	-	-	-	-	-
421	Miscellaneous Income or Loss	(1)	(169)	-	(5)	(3)	-	(4)	(1)	-	(23)
447	Impact Studies	-	-	-	-	-	-	-	-	-	-
500-559	Power Production	9,906	1,549	-	62	2,887	197	48,220	1,812	1,662	(1)
560-579	Transmission	-	321	-	24	914	103	157	-	-	-
580-599	Distribution	-	27	-	137	5,395	47	222	1	1	-
780-860	Trading	1	-	-	-	-	1	3	-	-	-
901-903	Customer Accounts Expense	7	11	-	-	2,985	2	-	-	-	-
905	Misc. Customer Accounts/Customer Assistance	-	-	-	(1)	517	-	-	-	-	-
906-917	Customer Service & Information	-	-	1	12	2,778	-	1	14	-	-
920	Salaries and Wages	760	12,763	3,499	15,788	54,809	17,194	2,336	6,056	613	595
921	Office Supplies and Expenses	642	7,069	528	4,793	22,596	2,367	1,518	1,866	280	333
922	Administrative Expense Transferred - Credit	885	(13,908)	685	11,162	15,087	2,293	4,308	626	178	1,646
923	Outside Service Employed	5	2,757	45	3,130	29,209	15,681	65	407	-	15
924	Property Insurance	-	43	-	3	-	-	-	-	-	-
925	Injuries and Damages	4	34	-	4,276	48	76	1	-	-	10
926	Employee Pensions and Benefits	16	46	-	84,440	162	13	29	2	-	2
928	Regulatory Commission Expense	-	-	-	-	-	-	-	-	-	-
930.1	General Advertising Expense	-	2	1	69	32	12	1	-	1	-
930.2	Miscellaneous General Expense	8	26	103	202	79	925	10	7	(1)	-
931	Rents	(1)	47,381	-	69	36,837	490	549	(3)	(1)	1
935	Maintenance of Structures and Equipment	3	13,734	-	1	7,502	-	84	-	-	-
403-405	Depreciation and Amortization Expense	-	13,598	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	224	3,245	61	26,134	1,049	266	1,016	231	125	52
409	Income Taxes	-	-	-	-	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	-	-	-	-	-
416	Cost and Expense of Merchandising	-	-	-	-	2	-	-	-	-	-
417	Administrative - Business Venture	-	-	-	-	2	-	162	-	-	14
418	Non-Operating Rental Income	-	64	-	-	-	-	-	-	-	-
426.1	Donations	-	-	2,161	273	-	1,882	2	-	-	66
426.3-426.5	Other Deductions	1	61	3,748	59	54	396	1	-	-	192
427	Interest on Long Term Debt	-	4,343	-	-	-	-	-	-	-	-
428	Amortization on Long Term Debt	-	427	-	-	-	-	-	-	-	-
430	Interest On Debt to Associate Companies	-	-	-	-	-	-	-	-	-	-
431	Other Interest Expense	-	-	-	13	-	-	-	-	-	-
432	Borrowed Funds - Construction - Credit	-	-	-	-	-	-	-	-	-	-
107	Construction Work in Progress	1,023	1,574	-	25	24,922	828	19,225	8,121	104	-
108	Retirement Work in Progress	13	(72)	-	-	-	4	3,622	36	-	-
120	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
124	Investments	-	1	-	(191)	-	-	-	-	-	-
151	Fuel Stock	-	-	-	52	36	30	293	-	-	1,597
152	Fuel Stock Expense Undistributed	131	-	-	49	37	79	1,193	-	-	317
163	Stores Expense Undistributed	2,715	(1)	-	9	1	-	5	1	-	-
182	Regulatory Assets	-	-	-	5	1,516	337	-	-	-	-
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-	-	-
184	Clearing Accounts	-	2,170	-	-	48	-	(12)	-	5	-
186	Miscellaneous Deferred Debits	4	37	-	567	77	496	524	44	-	582
188	Research, Development, or Demonstration Exp.	2	-	-	-	4	139	52	-	-	-
	TOTAL COST OF SERVICE	$ 16,348	$ 97,128	$ 10,832	$ 151,157	$ 209,582	$ 43,858	$ 83,583	$ 19,220	$ 2,967	$ 5,398

SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION							
ACCOUNT	DESCRIPTION OF ITEMS	NATURAL GAS OPER	NUCLEAR	OPERATIONS & TECH SVCS	PLANNING & BUS. DEV.	PUBLIC POLICY	RISK MANAGEMENT	TAX	TREASURY
454	Rents from Electric Properties - NAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other Electric Revenues	-	-	-	-	-	-	-	(2)
419	Interest Income - Other	-	-	-	-	-	-	(3)	(875)
421	Miscellaneous Income or Loss	-	-	-	(1)	-	-	-	(13)
447	Impact Studies	-	-	-	-	-	-	-	-
500-559	Power Production	-	970	1,586	137	2	735	(78)	385
560-579	Transmission	-	1	-	2,041	269	-	(10)	2
580-599	Distribution	-	-	1	2,768	-	-	(7)	3
780-860	Trading	3,071	-	-	-	-	-	-	-
901-903	Customer Accounts Expense	-	-	4	313	-	45	(37)	147
905	Misc. Customer Accounts/Customer Assistance	-	1	-	454	-	-	-	-
906-917	Customer Service & Information	-	1	-	2,924	1	-	1	-
920	Salaries and Wages	1,851	25	598	11,494	1,480	4,260	5,540	6,098
921	Office Supplies and Expenses	135	123	101	2,311	137	884	1,293	874
922	Administrative Expense Transferred - Credit	-	-	279	1,049	60	462	974	543
923	Outside Service Employed	1	(4)	3	7,120	5	521	2,454	1,830
924	Property Insurance	-	-	-	-	-	94	-	-
925	Injuries and Damages	-	-	-	1	-	2,470	-	5
926	Employee Pensions and Benefits	77	21	1	10	2	-	14	66
928	Regulatory Commission Expense	-	1	-	-	-	-	-	-
930.1	General Advertising Expense	-	-	-	1,020	-	-	(23)	(1)
930.2	Miscellaneous General Expense	1	30	6	914	-	-	1	590
931	Rents	-	-	-	1	-	4	-	(2)
935	Maintenance of Structures and Equipment	-	-	-	28	-	-	(36)	(2)
403-405	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	(34)	10	40	242	15	73	3,498	319
409	Income Taxes	-	-	-	-	-	-	76,481	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	-	124,713	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	-	(187,825)	-
416	Cost and Expense of Merchandising	-	-	-	-	-	-	-	-
417	Administrative - Business Venture	-	-	-	-	-	-	-	-
418	Non-Operating Rental Income	-	-	-	-	-	-	-	-
426.1	Donations	-	-	-	-	-	-	-	-
426.3-426.5	Other Deductions	-	-	-	45	-	-	85	-
427	Interest on Long Term Debt	-	-	-	-	-	-	-	636
428	Amortization on Long Term Debt	-	-	-	-	-	-	-	-
430	Interest On Debt to Associate Companies	-	-	-	-	-	-	-	3,656
431	Other Interest Expense	-	-	-	-	-	-	427	(60)
432	Borrowed Funds - Construction - Credit	-	-	-	-	-	-	-	(3,691)
107	Construction Work in Progress	56	-	351	569	-	23	3	1
108	Retirement Work in Progress	1	-	-	-	-	-	-	-
120	Nuclear Fuel	-	-	-	-	-	-	-	-
124	Investments	-	-	-	-	-	-	-	-
151	Fuel Stock	-	-	-	-	-	1	-	-
152	Fuel Stock Expense Undistributed	-	-	-	17	-	-	-	-
163	Stores Expense Undistributed	-	-	-	-	-	-	(1)	-
182	Regulatory Assets	-	-	-	1,274	41	-	24	91
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-
184	Clearing Accounts	-	-	-	2	-	-	-	-
186	Miscellaneous Deferred Debits	-	-	12	85	-	-	(1)	3
188	Research, Development, or Demonstration Exp.	-	-	2	-	-	-	-	1
	TOTAL COST OF SERVICE	$ 5,159	$ 1,179	$ 2,984	$ 34,818	$ 2,012	$ 9,572	$ 27,487	$ 10,604

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DEPARTMENTAL ANALYSIS OF SALARIES
(In Thousands except Number of Personnel)

NAME OF DEPARTMENT *Indicate each department or service function.*	DEPARTMENTAL SALARY EXPENSE INCLUDED IN AMOUNTS BILLED TO TOTAL AMOUNT	PARENT COMPANY	OTHER ASSOCIATES	NON ASSOCIATES	NUMBER OF PERSONNEL END OF YEAR
Service Groups (Overheads)	$ 24,675	$ 384	$ 24,218	$ 73	-
Accounting	12,310	171	12,139	-	390
Accounting & Financial Services	447	31	416	-	7
AEP ProServ	1,393	18	1,375	-	28
Audit Services	3,177	53	3,124	-	50
Corporate Communications	4,175	11	4,164	-	65
Corporate Development	6,421	173	6,248	-	91
Corporate Planning & Budgeting	4,927	29	4,897	1	61
Corporate Supply Chain	1,365	7	1,358	-	42
Customer & Community Services	52,733	367	52,366	-	1,392
Energy Delivery	6,440	6	5,731	703	99
Energy Delivery Support	14,420	148	14,268	4	344
Energy Distribution	15,597	34	15,563	-	283
Energy Services	30,415	85	30,187	143	443
Energy Transmission	34,132	29	33,937	166	501
Engineering Services	29,657	68	29,051	538	380
Environmental Affairs	1,508	1	1,507	-	11
Environmental Services	5,971	6	5,956	9	83
Executive Group	6,185	160	5,815	210	75
Fossil & Hydro Operations	9,263	16	9,247	-	129
General Services	8,483	23	8,460	-	239
Governmental Affairs	2,435	8	2,427	-	29
Human Resources	9,354	56	9,287	11	340
Information Technology	31,618	1,256	30,322	40	898
Legal	9,171	313	8,846	12	110
Maintenance Services & Regional Service Organization	52,617	39	52,550	28	1,079
Major Projects	8,951	57	8,633	261	104
Marketing & Business Development	1,344	11	1,333	-	14
Mining Operations	1,750	2	1,748	-	33
Natural Gas Operations	3,448	4	3,444	-	104
Nuclear	291	-	291	-	1
Operations & Technical Services	1,724	2	1,722	-	24
Planning & Business Development	11,993	14	11,972	7	155
Public Policy	387	1	386	-	6
Risk Management	2,960	8	2,942	10	58
Tax	3,300	30	3,270	-	50
Treasury	3,874	63	3,772	39	43
TOTALS	$ 418,911	$ 3,684	$ 412,972	$ 2,255	7,761

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
A & A Transfer Company	Consulting Services	$ 546
A. C. Coy Company	Consulting Services	239
ABB Power T & D Co. Inc.	Consulting Services	144
Abby Lane/Dana Temporaries, Inc.	Temporary Office and Accounting Services	183
Abilene, City of	Consulting Services	220
ABS Consulting Inc.	Consulting Services	936
Accenture LLP	Consulting Services	134
Accountemps	Temporary Office and Accounting Services	538
Accounting Principles	Temporary Office and Accounting Services	572
Active Development Group, Inc.	Consulting Services	160
Adecco Employment Services, Inc.	Temporary Office and Accounting Services	148
Aerotek. Inc.	Temporary Office and Accounting Services	293
Affiliates	Legal Services	139
Al Stalter & Associates	Consulting Services	505
Alliance Participants Admin. & Startup	Consulting Services	2,100
Alstom Power, Inc.	Engineering Services	275
American Payment Systems, Inc.	Collection Service	3,115
Analysis Group Economics	Consulting Services	505
Analysts International Corporation	Consulting Services	778
And Beyond Communications	Consulting Services	133
Applied Computer Sciences, Inc.	Consulting Services	136
Applied Performance Technologies, Inc.	Consulting Services	485
Arthur Andersen LLP	Consulting Services	574
ASAP Software Express, Inc.	Software Licence	1,740
Aspect Telecommunications Corporation	Telecommunications Services	713
AYCO Company, LP	Financial Services	274
Babcock & Wilcox Construction	Facilities Maintenance	303
Babcock Borsig Power	Engineering Services	3,488
Banctec Service Corporation	Software Licence	330
Bank of Oklahoma	Banking Services	805
Bell & Howell Company	Software Maintenance	134
BMC Software, Inc.	Software Licence	1,630
Booz-Allen & Hamilton Inc.	Consulting Services	2,456
Boston Consulting Group, Inc.	Consulting Services	204
Bowe Systec, Inc.	Training Services	330
Bracewell & Patterson	Legal Services	545
Bridger Group	Consulting Services	225
Buckeye Corporate Transportation	Transportation Services	235
Burgess, Burgess, Burgess, & Hightower	Legal Services	100
Burr Wolff LP	Financial Services	109
Buypay Traveler Express Co. Inc.	Wire Service	1,990
Cambridge Energy	Research & Development	388
Candle Corporation	Software Licence	1,309
Cap Gemini America	Consulting Services	252
Cap Gemini Ernst & Young US LLC	Consulting Services	357
Capital Recovery Service	Payment Recovery Service	129
CDI Corporation	Design Services	236
Charles River Associates, Inc.	Consulting Services	225
Cisco Systems, Inc.	Software Maintenance	424
Citibank NA	Financial Services	145
Clark, Thomas, & Winters	Legal Services	3,065
Climate Control Council	Consulting Services	159
Clinch River Corporation	Facilities Maintenance	264

ANNUAL REPORT OF American Electric Power Service Corporation

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Coghlan, Crowson, Fitzpatrick, Westbrook, & Worthington, LLP	Legal Services	179
Cognos Corporation	Software Licence	189
Com Net Communications Network	Telecommunications Services	482
Commercial Movers, Inc.	Office Furniture Transportation	136
Commerzbank	Advisory Services	306
Compaq Computer Corporation	Computer Support	548
Complete Business Solutions, Inc.	Consulting Services	315
Computer Associates International, Inc.	Software Licence	1,270
Computer Enterprises, Inc.	IT Support	177
Computer Project Resources, Inc.	Consulting Services	252
Compuware Corporation	Software Licence	2,053
Consultech	Engineering Services	185
Contract Counsel	Legal Services	373
Control Software, Inc.	Software Licence	124
Corechange, Inc.	Consulting Services	1,138
Corporate Executive Board	Consulting Services	119
Covansys	Software Maintenance	290
Credit Bureau Services	Credit Information Services	249
Crescent Real Estate	Plant Maintenance	1,400
Crowe Chizek	Software Licence	142
CSI-Maximus	Software Licence	104
D. B. Riley, Inc.	Engineering Services	2,871
Darwin Partners, Inc.	Supply Transportation	129
Data Dynamics, Inc.	Consulting Services	1,263
DAVOX Corporation	Consulting Services	158
DecisionOne Corporation	Consulting Services	156
Dell Computer Corporation	Consulting Services	3,866
Deloitte & Touche LLP	Auditing/Consulting Services	5,797
Doerner, Saunders, Daniel, & Anderson	Legal Services	374
Dominion Virginia Power	Consulting Services	1,805
Eftia OSS Solutions, Inc.	Telecommunications Services	624
Ejiva, Inc.	Consulting Services	113
Electric Power Research Institute	Research & Development	2,093
EMC Corporation	Computer Support	1,664
Emplifi, Inc.	Consulting Services	165
Enterprise for Education	Education Services	150
ENTEX IT Service	PC Workstation Support	315
Entropy, Inc.	Technical Support	122
Environmental Synergy, Inc.	Environmental Services	1,050
EPRI Solutions	Research & Development	1,767
Equifax Credit Information Service	Credit Information Services	857
Ernst & Young	Consulting Services	104
Everest Data Research, Inc.	Consulting Services	678
Expert Technical Consultants, Inc.	Consulting Services	114
Fireproof Records Center	Consulting Services	106
Fleet Business Credit Corporation	Software Maintenance	315
Franklin Computer Services Group, Inc.	Consulting Services	133
Frontier Associates LLC	Consulting Services	135
Frontway Network Solutions	Network & eBusiness Services	286
Gartner Group, Inc.	Industry Information Services	265
GE Capital Financial	Financial Services	178

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

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FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
GE Smallworld, Inc.	Software Maintenance	209
General Research	Training Services	1,042
Gentry, John M.	Engineering Services	124
Gill Elrod Ragon	Legal Services	143
Govind & Associates	Engineering Services	109
Grosh Consulting	Consulting Services	874
Group 1 Software, Inc.	Software Maintenance	501
Harris Corporation	Software Maintenance	157
Has, Inc.	IT Support	115
Hennegan	Legal Services	158
Henwood Energy Services, Inc.	Consulting Services	119
Hewitt Associates LLC	Consulting Services	101
Hewlett-Packard Company	Computer Support	366
Hitachi Credit America Corporation	Licence, Support, & Training Services	713
Holliday Enterprises, Inc.	Consulting Services	314
Hummingbird	Software Licence	128
Huntington National Bank	Financial Services	366
Hydro Quebec	Environmental Services	135
Hyperion Solutions	Software Licence	204
Idea Integration	Consulting Services	139
IKON, Inc.	Printing Services	101
Imprimis Group, Inc.	Temporary Office and Accounting Services	188
Indecon, Inc.	Consulting Services	713
Indus International	Consulting Services	2,134
Infinis, Inc.	Consulting Services	113
Informatica Corporation	Consulting Services	265
Information Builders, Inc.	Software Maintenance	377
Information Consulting Group, LLC	Consulting Services	170
Infosystems Corporation	Consulting Services	106
In-Plant Techniques Corporation	Printing Services	674
Interactive Business Systems, Inc.	Consulting Services	431
Intergraph Public Safety	Software Maintenance	120
Interiors Group, Inc.	Consulting Services	379
International Business Machine Corporation	Consulting Services	2,736
Internos LLC	Consulting Services	295
IOS Capital	Billing Services	183
Itron, Inc.	Consulting Services	220
ITS Technologies, Inc.	Engineering Services	204
J & M Bradley Enterprises, Inc.	Software Maintenance	301
J. D. Services, Inc.	Engineering Services	209
Jenkens & Gilchrist	Consulting Services	163
Jones, Day, Reavis, & Pogue	Legal Services	1,262
Jones, Galligan, Key, & Lozano	Legal Services	103
Kelly Services, Inc.	Temporary Office and Accounting Services	1,297
Key Personnel	Temporary Office and Accounting Services	729
Kforce.com	Temporary Office and Accounting Services	719
King Business Interiors, Inc.	Facilities Maintenance	317
Kleberg Law Firm	Legal Services	296
Landmark Systems Corporation	Software Licence	273
LaSalle Partners	Facilities Management	4,044
Leapnet, Inc.	Consulting Services	110
Lifecare.com, Inc.	Consulting Services	219
Linesoft, Inc.	Software Licence	2,979

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

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FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Lloyd, Gosseling, Blevins, Rochelle, Balwin, & Townsend, PC	Legal Services	192
Logica, Inc.	Consulting Services	5,686
Logical Resources, Inc.	Research Services	358
Love Envelopes, Inc.	Form Printing Services	153
Lucent Technologies, Inc.	Software Design	138
M/A-Com Wireless System	Engineering Services	326
Magnum Construction, Inc.	Facilities Maintenance	316
Management Recruiters	Employment Services	111
Manifest Solutions Corporation	Consulting Services	258
Market Strategies, Inc.	Consulting Services	1,221
Maxim Group	Consulting Services	2,403
Maximation, Inc.	Consulting Services	535
McAllen, City of	Consulting Services	559
Mercer Management Consulting, Inc.	Consulting Services	425
Merrill Lynch International	Financial Services	1,186
Meta Group, Inc.	Consulting Services	212
Metro Information Services	Software Maintenance	232
Microsoft Corporation	Software Licence	178
Mitem Corporation	Software Licence	116
MMC Enterprise Risk, Inc.	Financial Services	150
National City Bank	Financial Services	198
National Education Training Group	Training Services	287
National Records Centers, Inc.	Records Management	234
National Theatre for Children	Education Services	334
Navigant Consulting, Inc.	Consulting Services	234
NCO Financial Systems, Inc.	Financial Services	347
NCOE Payments	Financial Services	103
Necho Systems Corporation	Software Maintenance	205
Novadigm	Software Licence	169
Novatec Automations Systems, Inc.	Software Maintenance	160
Novient Inc.	Service Fees & Maintenance	165
NSI Consulting & Development, Inc.	Consulting Services	1,920
Odyssey Consulting Services, Inc.	Consulting Services	712
Officeteam	Temporary Office and Accounting Services	160
Ohio State University	Consulting Services	127
Olsten Staffing Services, Inc.	Temporary Office and Accounting Services	417
Option One	Temporary Office and Accounting Services	152
Oracle Corporation	Training Services	1,231
Origin Technology in Business	Consulting Services	614
OSI Outsourcing Services, Inc.	Call Handling Service	3,381
PA Consulting Services, Inc.	Consulting Services	.195
Pacific Telematics, Inc.	Consulting Services	120
Paros Business Partners, Inc.	Consulting Services	585
Paul J. Ford & Company	Consulting Services	300
Peace Software	Software Licence	264
People.com Consultants, Inc.	Consulting Services	111
PeopleSoft USA, Inc.	Consulting Services	374
Porter, Wright, Morris, & Arthur	Legal Services	873
Potter & Associates, Inc.	Training Services	164
Power Costs, Inc.	Software Licence	194
Power Tecnologies, Inc.	Software Support	132
Powerplan Consultants, Inc.	Consulting Services	383

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

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FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Pratt & Grant	Consulting Services	380
Preferred Technology	Software Support	413
PriceWaterhouseCoopers LLP	Consulting Services	1,438
Princeton Softech, Inc.	Software Licence	365
Productivity Point International	Consulting Services	122
Progressive Marketing, Inc.	Printing Services	187
Project Control	Consulting Services	330
Protec Group, Inc.	Consulting Services	803
Provide Technologies, LLC	Consulting Services	116
Prudential Insurance Company	Financial Services	312
Quick Solutions, Inc.	Consulting Services	1,250
R. Dorsey & Company, Inc.	Consulting Services	622
Rapidigm	Consulting Services	1,744
Ray & Berndtson, Inc.	Legal Services	546
Remedy Corporation	Computer Support	410
Renaissance Worldwide IT Consulting Services, Inc.	Consulting Services	539
Robert Half International, Inc.	Consulting Services	561
Roland Technical Staffing, Inc.	Consulting Services	264
RSA Security	Software Licence	478
Sarcom, Inc.	Consulting Services	100
SAS Institute, Inc.	Software Licence	133
Sensible Software Solutions, LLC	Software Support	176
SHL USA, Inc.	Consulting Services	140
Sidley & Austin	Legal Services	714
Siemans Business Services, Inc.	Software Installation	512
Skillsoft Corporation	Training Services	406
Small World Systems, Inc.	Software Licence	436
Sodexho Marriott Services	Catering Services	636
Software AG of North America	Software Installation	285
Software Support Group	Consulting Services	160
Solomon Associates, Inc.	Consulting Services	116
Southwest Power Pool	Engineering Services	822
Spectrum Solutions, Inc.	Consulting Services	117
Spherion Corporation	Consulting Services	171
Spidertech, Inc.	Telecommunications Services	120
Standley & Gilcrest	Legal Services	115
Steptoe & Johnson, LLP	Legal Services	2,160
Sterling Commerce Interchange	Software Licence	234
Stone & Webster Consultants	Consulting Services	487
Storage Technology Corporation	Software Maintenance	142
Summitt Construction, Inc.	Consulting Services	161
Sun Technical Services, Inc.	Consulting Services	4,378
Superior Tech Resources, Inc.	Consulting Services	119
Systor Security Solutions, Inc.	Software Licence	310
Taylor, Burrage, Foster, Mallett, Downs, & Ramsey	Legal Services	166
Techmate, Inc.	Consulting Services	724
Teksystems	Consulting Services	458
Tesseract	Payroll Benefits Maintenance	187
Texas Print Services, Inc.	Printing Services	266
Thermal Energy International Inc.	Engineering Services	258
Thomas Glover Associates, Inc.	Consulting Services	151
Topographic Mapping Company	Mapping Services	113
Trammell Crow Company	Office Building Security	359

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

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FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Twenty First Century	Consulting Services	187
Ubics, Inc.	Consulting Services	308
UBS Warburg LLC	Financial Services	708
Uni Data Systems	Consulting Services	145
Unisys Corporation	Consulting Services	1,452
United Parcel Service	Delivery Service	392
URS Corporation	Engineering Services	157
Usertech	Consulting Services	1,309
Van Ness Feldman	Legal Services	105
Varo Engineers, Ltd.	Engineering Services	358
Venture Sum Corporation	Pole Maintenance	107
Vigilinx, Inc.	Consulting Services	405
Vinson & Associates	Temporary Office and Accounting Services	915
Vinson & Elkins LLP	Legal Services	851
Vision Technologies, Inc.	Software Implementation	150
Wagstaff, Alvis, Stubbeman, Seamster, & Longacre, LLP	Legal Services	397
White, Coffey, Galt, & Fite, PC	Legal Services	469
Wilkinson, Carmody, & Gilliam	Legal Services	597
William M. Mercer, Inc.	Consulting Services	105
Wiseman Construction Company, Inc.	Facilities Maintenance	835
Woods, Rogers, & Hazelgrove PLC	Legal Services	283
Xerox Corporation	Printing Services	400
Others (3,268 under $100,000)	Various Services	20,437
TOTAL		$ 31,072

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

EMPLOYEE PENSIONS AND BENEFITS - ACCOUNT 926
(In Thousands)

Instructions: Provide a listing of each pension plan and benefit program provided by the service company. Such listing should be limited to $25,000.

DESCRIPTION	AMOUNT
Medical	$ 39,158
Deferred Compensation Benefits	955
Other Postretirement Benefits	18,682
Savings Plan	7,695
Supplemental Pension Plan	7,990
Retirement Plan	(11,400)
Long-Term Disability	3,091
Group Life Insurance	(6,886)
Dental Insurance	2,879
Employee Educational Assistance	553
Training Administration Expense	2,188
Corporate Owned Life Insurance	1,976
Post Employment Benefits	19,530
Employee Awards and Events Program	494
Miscellaneous	367
TOTAL	$ 87,272

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For the Year Ended December 31, 2001

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definition. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
General Advertising	Blue Ridge Public Television	$ 3
	Herald-Dispatch	3
	Macromedia	8
	Nationwide Advertising Service	11
	Ohio Newspaper Services, Inc.	8
	Our Texas Magazine	4
	Sha-Cas Inc.	5
	West Virginia Press Services	8
	Others	117
	SUBTOTAL	167
Consumer Education	Charles Ryan Associates, Inc.	3
	Democracy Data & Communication	61
	Diversified Educational	20
	Giacomazza Giuseppe	8
	Hartman, Lee & Sons, Inc.	3
	Moore Syndication, Inc.	27
	Progressive Marketing, Inc.	32
	Promotional Management Group, Inc.	11
	Salter & Associates	3
	Others	53
	SUBTOTAL	221
Consumer Surveys	International Robotics, Inc.	5
	Eagle Exhibits	8
	Enterprise For Education	135
	Market Strategies, Inc.	897
	TQS Research, Inc.	65
	Others	50
	SUBTOTAL	1,160

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For the Year Ended December 31, 2001

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definition. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Salaries, salary related expenses, overheads and other expenses		1,248
	SUBTOTAL	1,248
	TOTAL	$ 2,796

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For the Year Ended December 31, 2001

MISCELLANEOUS GENERAL EXPENSES - ACCOUNT 930.2
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Payments and expenses permitted by Section 321(b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441 (b)(2)) shall be separately classified.

DESCRIPTION	AMOUNT
Salaries, Salary Related Expenses and Overheads	$ 3,580
Membership Fees and Dues	837
Directors' Fees and Expenses	127
Manage Cash	434
Electric Power Research Institute Fees	433
Engineer and Design Telecommunication and Transmission Facilities	171
Promote Positive Employee Relations	52
Continuity Planning	50
Individual Shareholder Support	36
Manage Investments	30
Construct Transmission Station Facilities	29
Develop and Deploy IT Infrastructure	24
Outside Legal Services	22
Manage Short Term Funding	16
Sell Nonregulated Products	15
Manage Factoring	15
Provide For Miscellaneous Employee Benefits	13
Manage Relocation Process	12
Promote Regulated Products	10
Maintain Shops and Labs	8
Miscellaneous	177
TOTAL	$ 6,091

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For the Year Ended December 31, 2001

RENTS - ACCOUNT 931
(In Thousands)

Instructions: Provide a listing of the amount included in Account 931, "Rents", classifying such expenses by major groupings of property, as defined in the account definition of the Uniform System of Accounts.

TYPE OF PROPERTY	AMOUNT
Office Space	$ 48,447
Computer Software	367
Computer Equipment	31,522
Office Equipment	514
Telecommunications Equipment	5,431
Miscellaneous	3,601
TOTAL	$ 89,882

TAXES OTHER THAN INCOME TAXES - ACCOUNT 408
(In Thousands)

Instructions: Provide an analysis of Account 408 "Taxes Other Than Income Taxes". Separate the analysis into two groups: (1) other than U.S. Government taxes, and (2) U.S. Government taxes. Specify each of the various kinds of taxes and show the amounts thereof. Provide a subtotal for each class of tax.

DESCRIPTION	AMOUNT
Taxes Other Than U.S. Government Taxes	
State Unemployment Taxes	$ 407
Property, Franchise, Ad Valorem and Other Taxes	7,078
SUB-TOTAL	7,485
U.S. Government Taxes	
Social Security Taxes	34,940
Federal Unemployment Taxes	484
SUB-TOTAL	35,424
TOTAL	$ 42,909

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DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION		AMOUNT
Abilene Christian University	Educational	$	5
Abilene Industrial Foundation	Community		20
AEP Operation Feed	Community		4
AEP United Way Campaign	Community		8
Alpine Main St	Community		4
American Cancer Society	Community		5
American Coal Foundation	Community		4
American Heart Association	Community		9
American Red Cross	Community		330
Angelo State University	Educational		24
Annapolis Center	Community		25
Aransas Co Independent	Community		3
ASME Foundation	Community		25
Aspermont BDC Inc.	Community		6
Atascosa County	Community		22
Atascosa County Economic	Community		5
B R E A D Organization	Community		5
Balletmet	Community		6
Bay Area Citizens	Community		3
Bayfest Inc	Community		5
Bee Community Action Agency	Community		9
Big Bend Community Action Comm	Community		7
Blazer, Paul High School	Educational		3
Boy Scouts of America	Community		6
Boys & Girls Club	Community		37
Boys & Girls Club of Laredo	Community		3
Brookings Institution	Educational		10
Brush Country Bus Resource CT	Community		10
Burton McCumber & Cortex LLP CPA	Community		10
Cactua Bowl	Community		3
Cameron & Willacy Counties	Community		39
Camp, Inc.	Community		15
Capital Square Foundation	Community		20
Capitol Wings Airline, Inc.	Community		6
Central Texas Opportunities	Community		7
Chamber of Commerce	Community		28
Chamber of Commerce Port Isabel	Community		3
Champion of Children Fund	Community		5
Childrens Hospital Foundation	Community		25
Coastal Bend College	Educational		5

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Columbus Association For Performing Arts	Community	10
Columbus Metropolitan Club	Community	4
Columbus Museum of Art	Community	7
Columbus School For Girls	Educational	5
Columbus Speech & Hearing Center	Community	4
Columbus State Community College	Educational	23
Columbus Symphony Orchestra	Community	65
Columbus Technology Leadership	Community	25
Columbus Zoo	Community	12
Combined Community Action Inc.	Community	17
Communities in Sch Golf Tourn	Community	3
Community Action Committee of	Community	38
Community Action Corp	Community	10
Community Action Council	Community	32
Community Action Program	Community	19
Community Council of South	Community	36
Community Council-Southwest TX	Community	19
Community Service Agency	Community	14
Cornell University	Educational	9
Corpus Christi Chamber of Commerce	Community	21
Corpus Christi Hispanic Chamber	Community	4
Corpus Christie Regional Economic Development Corporation	Community	15
COSI Columbus	Community	50
Council for Ethics	Community	5
Crystal City Spinach Festival	Community	3
CSA of Dimmitt, LaSalle	Community	3
Dallas Zoological Society	Community	10
Decorative Arts Center of Ohio	Community	15
Delay Foundation Golf Invitational	Community	5
Directions for Youth	Community	5
Driscoll Childrens Hospital	Community	13
East-West Powerboat Shoot-out	Community	15
Economic Action Committee	Community	6
El Grito De Laredo Fest	Community	5
Environmental Education	Community	26
Financial Accounting Foundation	Educational	4
Food Bank of Corpus Christi	Community	4
Foundation For Environmental Education	Community	25
Fox, Robert K Family Y	Community	30
Freer, City Of	Community	3
Fundacion Amigos De La Natural	Community	33

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Galveston County Community	Community	7
Global Green USA	Community	5
Goliad County	Community	5
Good Shepherd Foundation	Community	51
Governors Residence Foundation	Community	10
Grandview Heights High School	Educational	10
Great Texas Birding Classic	Community	15
Greater Dallas Chamber	Community	3
Greater Longview United Way, Inc.	Community	17
Gulf Coast Bird Observatory	Community	6
Habitat For Humanity	Community	32
Harbor Lights	Community	10
Harlingen Area Education Foundation	Community	3
Hawkwatch International	Community	4
Heard Natural Science Museum + A79	Community	5
Helping Hands Of Kilgore	Community	7
Hidalgo Chamber Of Commerce	Community	4
I Know-I Can	Educational	7
Indiana State Museum	Community	25
Institute For Public Relations	Community	8
Intl Baccalaureate Program	Community	10
Jarvis Christian College	Educational	3
Junior Achievement	Community	75
Junior League	Community	68
Juvenile Diabetes Foundation	Community	7
Keystone Center	Community	25
Kingsville Economic Development	Community	6
Kleberg County Humans Services	Community	10
L I F E Downs	Community	8
Lancaster Country Club	Community	3
Lancaster Festival Inc.	Community	5
Laredo Development Foundation	Community	7
Laredo-Webb County Community	Community	32
Leukemia & Lymphoma Society	Community	9
Lucio, Eddie Scholarship Fund	Educational	5
Make-A-Wish Foundation	Community	5
Massachusetts Institute Of Technology	Educational	5
Mcallen Chamber Of Commerce	Community	9
Meeting Connection Inc.	Community	4
Mexican Folklore School Of Dance	Educational	3
Middle Rio Grande	Educational	7

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Monumento Tejano	Community	10
Mount Carmel Health	Community	3
Muscular Dystrophy Association	Community	4
Napp Medical Center	Community	5
National Academy Of Engineering	Educational	5
National Alliance Of Business	Community	5
National Energy Education Development	Community	5
National First Ladies Library	Community	10
National Governors Association	Community	12
National Hispanic Scholarship	Educational	4
National Press Foundation	Community	3
National Wild Turkey Federation	Community	15
Natural Resources Of Texas	Community	30
Nature Conservancy	Community	77
Nature Conservancy Of Texas	Community	15
Need Project	Community	9
Nueces County Community Action	Community	23
Nueces County Community Action	Community	23
Nueces County Jr. Livestock Show & Sale	Community	6
Ohio Academy Of Science	Educational	4
Ohio Chamber Of Commerce	Community	27
Ohio Dominican College	Educational	5
Ohio Energy Project	Community	35
Ohio Erie To Trail Fund	Community	5
Ohio Foundation Of Independent Colleges Inc.	Community	27
Ohio River Valley	Community	10
Ohio State University	Educational	90
Oklahoma Centennial Comm Fund Inc.	Community	5
Oklahoma State University	Educational	15
Ontario Power Generation Inc..	Community	10
Opera Columbus	Community	8
ORSANCO (Ohio River Sweep)	Community	5
Our Lady Of Sorrows School	Educational	8
Pals Foundation-South Ward	Community	6
Panhandle Community Services	Community	6
Panola County	Community	4
Peregrine Fund	Community	10
Posada Hotel/Suites	Community	6
Princeton University	Educational	14
Project Future	Community	15
Public Relations Seminar	Community	6

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Raymondville Municipal Golf Course	Community	3
Refugio County	Community	3
Rensselaer Polytechnic Institute	Educational	17
Resources For The Future	Community	50
Rio Grande, City Of	Community	10
Rockport-Fulton Good Samaritan	Community	13
Rolling Plains Management Corp	Community	5
Rosemont Center	Community	10
Salvation Army	Community	88
San Angelo Chamber Of Commerce	Community	13
San Angelo Museum Of Fine Arts	Community	3
San Patricio Community	Community	11
San Patricio County	Community	5
Save Goodfellow Fund	Community	5
Science & Mathematics Network	Educational	5
Senate Hispanic Research	Community	10
Simon Kenton Council	Community	62
South Texas Celebrity Weekend	Community	6
South Texas Public Broadcasting	Community	35
South Texas Spaceport Consort	Community	10
Southeast Community Business & Education	Community	10
Streets Of Laredo Mall	Community	3
Sul Ross State University	Educational	18
Sunny Glen Home	Community	5
Taylor University	Educational	5
Tech Prep Showcase	Community	3
Tex Agricultural Exp Station	Community	5
Texas A & M University	Educational	96
Texas Border Infrastructure	Community	3
Texas Business & Education	Community	5
Texas Charitable Fund	Community	15
Texas Citrus Fiesta	Community	3
Texas Conference For Women	Community	10
Texas Conservative Forum	Community	10
Texas Parks And Wildlife Dept	Community	3
Texas State Aquarium	Community	10
Texas Tech University	Educational	5
Texas Water Foundation	Community	5
Tom Green County Community	Community	6
Tom Green County Health Dept	Community	17
U.S. National Committee-CIGRE	Community	5

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
United Negro College Fund	Educational	23
United Way	Community	600
University Of Notre Dame	Educational	7
University Of Texas	Educational	17
Upshur County Aide Bank	Community	16
USS Lexington	Community	3
Utilitree Carbon Company	Community	20
UTPA Athletic Center	Community	10
UTPA Border Summit	Community	10
Valley Interfaith	Community	5
Victoria Botanical Garden	Community	8
Victoria Chamber Of Commerce	Community	3
Victoria County United Way	Community	8
Victoria Economic Development	Educational	8
Virginia Polytechnic Institute	Educational	15
Virginia Tech Foundation Inc.	Community	14
Volunteer Ohio	Community	10
Washingtons Birthday Celebration	Community	15
Webb County/Christmas Offering	Community	7
West Texas Rehabilitation Center	Community	29
West Virginia University	Educational	16
Wildlife Habitat Council	Community	4
Windcrest Alzheimers	Community	3
Young Men's Christian Association	Community	19
Young Women's Christian Association	Community	4
Zapata County ISD	Community	4
Employees and Others (Salaries, salary related expenses, overheads and other expenses)	Various	577
Others		499
TOTAL		$ 5,106

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

OTHER DEDUCTIONS - ACCOUNTS 426.3 - 426.5
(In Thousands)

Instructions: Provide a listing of the amount included in Accounts 426.3 through 426.5, "Other Deductions", classifying such expenses according to their nature.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Expenditures for Certain Civic, Political & Related Activities	Company employee and administrative costs for civic, political and related activities	$ 4,604
Other Miscellaneous Deductions	Various	1,800
TOTAL		$ 6,404

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SCHEDULE XVIII - NOTES TO STATEMENT OF INCOME

Instructions: The space below is provided for important notes regarding the statement of income or any account thereof. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.

1) Page 21 "Analysis of Billing - Associate Companies" captures the category "Compensation for Use of Capital". The following items are included in this category (in thousands):

Interest Income - Associated	$	(873)
Interest Income - Nonassociated		(1)
Interest on Long Term Debt - Notes		636
Interest to Associated Companies - Money Pool		2,914
Allowance for Borrowed Funds Used During Construction		(3,691)
Total Compensation for Use of Capital	$	(1,015)

2) See Notes to Financial Statements on Page 19.

ORGANIZATION CHART

Chairman, Chief Executive Officer & President

- Vice Chairman & Chief Operating Officer
  - Energy Services
  - Mining Operations
  - Energy Delivery
    - Energy Transmission
    - Energy Distribution
    - Energy Delivery Support
    - Planning & Business Development
    - Customer Operations
  - Nuclear
  - Operations & Technical Services
  - Fossil & Hydro Operations
  - Natural Gas Operations
  - AEP ProServ
    - Marketing & Business Development
    - Maintenance Services & Regional Service Organization
    - Major Projects
    - Engineering Services
    - Environmental Services
    - Accounting and Financial Services
- Policy, Finance and Strategic Planning
  - Legal
  - Corporate Communications
  - Governmental Affairs
  - Environmental Affairs
  - Public Policy
  - Corporate Development
  - Accounting
  - Corporate Planning & Budgeting
  - Treasury
  - Audit Services (NOTE)
  - Tax
  - Risk Management
- Shared Services
  - General Services
  - Human Resources
  - Information Technology
  - Corporate Supply Chain

NOTE: Audit Services reports to the Audit Committee of the Board of Directors of American Electric Power Company, Inc. and administratively to the Executive Vice President - Policy Finance and Strategic Planning.

METHODS OF ALLOCATION

Service Billings

1	Number of Bank Accounts
2	Number of Call Center Telephones
3	Number of Cell Phones/Pagers
4	Number of Checks Printed
5	Number of Customer Information System Customer Mailings
6	Number of Commercial Customers (Ultimate)
7	Number of Credit Cards
8	Number of Electric Retail Customers (Ultimate)
9	Number of Employees
10	Number of Generating Plant Employees
11	Number of General Ledger Transactions
12	Number of Help Desk Calls
13	Number of Industrial Customers (Ultimate)
14	Number of Job Cost Accounting Transactions
15	Number of Non-UMWA Employees
16	Number of Phone Center Calls
17	Number of Purchase Orders Written
18	Number of Radios (Base/Mobile/Handheld)
19	Number of Railcars
20	Number of Remittance Items
21	Number of Remote Terminal Units
22	Number of Rented Water Heaters
23	Number of Residential Customers (Ultimate)
24	Number of Routers
25	Number of Servers
26	Number of Stores Transactions
27	Number of Telephones
28	Number of Transmission Pole Miles
29	Number of Transtext Customers
30	Number of Travel Transactions
31	Number of Vehicles
32	Number of Vendor Invoice Payments
33	Number of Workstations
34	Active Owned or Leased Communication Channels
35	Avg. Peak Load for past Three Years
36	Coal Company Combination
37	AEPSC past 3 Months Total Bill Dollars
38	AEPSC Prior Month Total Bill Dollars
39	Direct
40	Equal Share Ratio
41	Fossil Plant Combination
42	Functional Department's Past 3 Months Total Bill Dollars
43	KWH Sales (Ultimate Customers)
44	Level of Construction - Distribution
45	Level of Construction - Production
46	Level of Construction - Transmission
47	Level of Construction - Total
48	MW Generating Capability
49	MWH's Generation
50	Current Year Budgeted Salary Dollars
51	Past 3 Mo. MMBTU's Burned (All Fuel Types)
52	Past 3 Mo. MMBTU's Burned (Coal Only)
53	Past 3 Mo. MMBTU's Burned (Gas Type Only)

METHODS OF ALLOCATION

54	Past 3 Mo. MMBTU's Burned (Oil Type Only)
55	Past 3 Mo. MMBTU's Burned (Solid Fuels Only)
56	Peak Load / Avg. No. Cust / KWH Sales Combination
57	Tons of Fuel Acquired
58	Total Assets
59	Total Assets less Nuclear Plant
60	AEPSC Annual Costs Billed (Less Interest And/or Income Taxes as Applicable)
61	Total Fixed Assets
62	Total Gross Revenue
63	Total Gross Utility Plant (Including CWIP)
64	Total Peak Load (Prior Year)
65	Hydro MW Generating Capability
66	Number of Forrest Acres
67	Number of Dams
68	Number of Plant Licenses Obtained
69	Number of Nonelectric OAR Invoices
70	Number of Transformer Transactions
71	Tons of FGD Material
72	Tons of Limestone Received
73	Total Assets, Total Revenues, Total Payroll
74	Total Leased Assets
75	Number of Banking Transactions

Convenience Billings

Specific Identification Ratio
(based on known and pertinent factors)
Asset Ratio
Expense Budget Ratio
Contribution Ratio
Equal Share Ratio
Gross Annual Payroll Dollars Ratio
Coal Production Ratio
Kilowatt Hours Sales (KWH) Ratio
Number of Employees Ratio
Number of Customers Ratio
Number of Vehicles Ratio

ANNUAL STATEMENT OF COMPENSATION FOR USE OF CAPITAL BILLED

The following annual statement was supplied to each associate company in support of the amount of compensation for use of capital billed during 2001:

In accordance with Instruction 01-12 of the Securities and Exchange Commission's Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, American Electric Power Service Corporation submits the following information on the billing of interest on borrowed funds to associated companies for the year 2001:

A. Amount of interest billed to associate companies is contained on page 21, Analysis of Billing.

B. The basis for billing of interest to the associated companies is based on the Service Company's prior year Attribution Basis "AEPSC Annual Cost Billed ."

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2001

SIGNATURE CLAUSE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935 and the rules and regulations of the Securities and Exchange Commission issued thereunder, the undersigned company has duly caused this report to be signed on its behalf by the undersigned officer thereunto duly authorized.

American Electric Power Service Corporation
(Name of Reporting Company)

G E Laurey
(Signature of Signing Officer)

G. E. Laurey — Assistant Controller Regulated Accounting
(Printed Name and Title of Signing Officer)

Date: April 26, 2002

KPSC Case No. 99-149
Attachment 3A
Item No. 1

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U5S
ANNUAL REPORT

For the year ended December 31, 2000

Filed Pursuant to the Public Utility Holding Company Act of 1935
by

AMERICAN ELECTRIC POWER COMPANY, INC.
1 Riverside Plaza, Columbus, Ohio 43215

AMERICAN ELECTRIC POWER COMPANY, INC.

FORM U5S – ANNUAL REPORT
For the Year Ended December 31, 2000

TABLE OF CONTENTS

ITEM 1. SYSTEM COMPANIES AND INVESTMENT THEREIN AS OF DECEMBER 31, 2000.

Name of Company (1)	Number of Common Shares Owned (2)	Percent of Voting Power (3)	Issuer Book Value (P) (4)	Owner's Book Value (P) (5)
			(in thousands)	
American Electric Power Company, Inc. (AEP)	None	None	None	None
AEP Communications, Inc. (AEPC)	100 Shares	100	$ (12,090)	$ (12,090)
AEP Communications, LLC (AEPCLLC)	Uncertificated	100	(14,669)	(14,669)
American Fiber Touch, LLC		48 (S)	6,937	6,937
AEP Fiber Venture, LLC (AEPFIBER)	Uncertificated	100	34,091	34,091
America's Fiber Network, LLC		48 (R)	55,362	55,362
Datapult, LLC	Uncertificated	100	58	58
Datapult Partnership (DATAPTR)	Partnership	0.5 (Q)	59	58
Datapult Limited Partnership	Partnership	49.75 (Q)	5,774	3,412
AEP Energy Services, Inc. (AEPES)	200 Shares	100	(3,743)	(3,740)
AEP Generating Company (AEGCo)	1,000 Shares	100	34,156	34,156
AEP Investments, Inc. (AEPINV)	100 Shares	100	18,498	18,498
AEP Power Marketing, Inc.	100 Shares	100	-	-
AEP Pro Serv, Inc. (AEPRO) (A)	110 Shares	100	(1,092)	(1,092)
AEP Retail Energy LLC (AEPRELL)	Uncertificated	100	(113)	(113)
American Electric Power Service Corporation (AEPSC)	13,500 Shares	100	2,550	2,550
AEP Resources, Inc. (AEPR)	100 Shares	100	210,007	210,989
AEP Delaware Investment Company(AEPDI)	Shares	100	1,355	1,353
AEP Holdings I CV (AEPHLD)	Partnership	1	1,317	1,284
AEP Holdings II CV (AEPHLDII)	Partnership	0.8	543	577
AEP Energy Services Limited (AEPES-UK)	.01 Shares	0.8	172	172
AEP Energy Services Gmbh	Uncertificated	0.8	-	-
AEP Energy Services (Switzerland) GmbH	Uncertificated	0.8	-	-
AEP Funding Limited	.01 Shares	0.8	-	-
AEPR Global Investments B.V. (AEPRGI)	.3 Shares	0.8	-	-
Energia DeMexicali, S De R.L.	Uncertificated	- (B)	-	-
AEPR Global Holland Holding B.V. (AEPRGHH)	.3 Shares	0.8	-	-
AEPR Global Ventures B.V. (AEPRGV)	.31 Shares	0.8	(2)	(3)
Energia DeMexicali, S De R.L.	Uncertificated	0.8 (B)	2	2
Australian Energy International Pty. Ltd.	1 Shares	0.1 (C)	-	-
AEI (Loy Yang) Pty. Ltd.	.40 Shares	0.8	-	-
Intergen Denmark, Aps	Partnership	.4	-	363
Compresion Bajio S de R.L. de C.V.	Shares	.4	35	35
Yorkshire Power Group Limited	440,001 Shares	.1 (K)	770	721
Yorkshire Cayman Holding Limited	Shares	.6	-	-
Yorkshire Holdings plc	300 Shares	.6	-	-
Yorkshire Electricity Group plc	955,626 Shares	.6	-	-
Yorkshire Power Finance Limited	.1 Shares		-	-

ITEM 1. (CONTINUED)

Yorkshire Power Finance Limited	6 Shares	.2		-	-
AEP Delaware Investment Company II (AEPDII)(B)	1,000 Shares	100		75,476	75,482
AEP Resources do Brasil Ltda		.1	(T)	-	-
AEP Holdings II CV (AEPHLDII)	Partnership	15		10,175	10,200
AEP Energy Services Limited (AEPES-UK)	.15 Shares	15		3,215	3,206
AEP Energy Services Gmbh	Uncertificated	15		4	4
AEP Energy Services (Switzerland) GmbH	Uncertificated	15		2	2
AEP Funding Limited	1 Shares	15		-	-
AEPR Global Investments B.V. (AEPRGI)	6 Shares	15		-	-
Energia DeMexicali, S De R.L.	Uncertificated	-	(B)	-	-
AEPR Global Holland Holding B.V. (AEPRGHH)	6 Shares	15		-	-
AEPR Global Ventures B.V. (AEPRGV)	6 Shares	15		(35)	(38)
Energia DeMexicali, S De R.L. de C.V. (ENERGIA)	Uncertificated	15	(B)	35	35
Australian Energy International Pty. Ltd.	15 Shares	2.4	(C)	-	-
AEI (Loy Yang) Pty. Ltd.	.15 Shares	15		-	-
Intergen Denmark, Aps	Partnership	7.5		6,811	6,811
Compresion Bajio S de R.L. de C.V.		7.5		650	650
AEP Resources do Brasil ltda		99.9	(T)	-	-
AEP Energy Management, L.L.C.	Uncertificated	100		298	298
AEP Holdings I CV (AEPHLD)	Partnership	99		130,357	127,182
AEP Holding II CV (AEPHLDII)	Partnership	84.2		57,115	48,612
AEP Energy Services Limited (AEPES-UK)	.84 Shares	84.2		3,052	3,052
AEP Energy Services Gmbh	Uncertificated	84.2		23	22
AEP Energy Services (Switzerland) Gmbh	Uncertificated	84.2		10	10
AEP Funding Limited	.84 Shares	84.2		-	-
AEPR Global Investments B.V. (AEPRGI)	33.7 Shares	84.2		17	17
Energia DeMexicali, S De R.L.	Uncertificated	-	(B)	-	-
AEPR Global Holland Holding B.V. (AEPRGHH)	33.7 Shares	84.2		(1)	(1)
AEPR Global Ventures B.V. (AEPRGV)	33.7 Shares	84.2		(196)	(215)
Energia DeMexicali, S De R.L.	Uncertificated	84.2	(B)	199	199
Australian Energy International Pty. Ltd.	84 Shares	13.5	(C)	-	-
AEI (Loy Yang) Pty. Ltd.	.84 Shares	84.2		-	-
Intergen Denmark, Aps	Partnership	42.1		38,230	38,230
Compresion Bajio S de R.L. de C.V.	Shares	42.1		3,647	3,647
Yorkshire Power Group Limited	43,560,000 Shares	9.9	(K)	76,230	71,371
Yorkshire Cayman Holding Limited	Shares	19.4		-	-
Yorkshire Holdings plc	9,700 Shares	19.4		-	-
Yorkshire Electricity Group plc	30,898,565 Shares	19.4		-	-
Yorkshire Power Finance Limited	3.9 Shares	.4		-	-

ITEM 1. (CONTINUED)

Yorkshire Power Finance Limited	190 Shares	19.4		-	-
AEP Resources Australia Holdings Pty Ltd (AEHOL)	1 Shares	100		339,637	339,627
AEP Resources CitiPower I Pty Ltd (AECP1)	1 Shares	100		77,704	77,704
Australia's Energy Partnership (AEPNP)	Partnership	99	(D)	998,305	998,305
Marregon (No. 2) Pty Ltd (LDC1)	179,190,000 Shares	99		1,038	1,038
CitiPower Pty (CTP)	4.95 Shares	99		5,051	5,051
CitiPower Trust (TRUST)	Uncertificated	99		973,916	973,916
Marregon Pty Ltd (AEMAR)	.99 Shares	99		-	-
AEP Resources CitiPower II Pty Ltd (AECP2)	1 Shares	100		1,767	1,767
Australia's Energy Partnership (AEPNP)	Partnership	1	(D)	10,084	10,084
Marregon (No. 2) Pty Ltd (LDC1)	1,810,000 Shares	1		10	10
CitiPower Pty (CTP)	.05 Shares	1		51	51
CitiPower Trust (TRUST)	Uncertificated	1		9,838	9,838
Marregon Pty Ltd (AEMAR)	.01 Shares	1		-	-
AEP Resources Australia Pty., Ltd. (AEPRA)	3,753,752 Shares	100		17,169	17,169
Pacific Hydro Limited	23,478,300 Shares	20	(E)	15,196	17,096
AEP Resources Limited (AEPRL)	1 Shares	100		413	413
AEP Resources Gas Holding Company (AEPRGH)	10 Shares	100		331,114	331,114
AEP Energy Services Investments, Inc. (AEPRINV)	100 Shares	100		124,086	124,086
LIG Pipeline Company (LIGPIPE)	100 Shares	100		124,049	124,049
LIG, Inc. (LIGINC)	100 Shares	100		12,391	12,391
Louisiana Intrastate Gas Company, L.L.C. (LIG)	100 Shares	10	(F)	12,404	12,404
LIG Chemical Company (LIGCHEM)	100 Shares	10		(776)	(776)
LIG Liquids Company, L.L.C. (LIGLIQ)	10 Shares	1	(G)	145	145
LIG Liquids Company, L.L.C. (LIGLIQ)	90 Shares	9	(G)	1,308	1,308
Tuscaloosa Pipeline Company (TUSCALOOSA)	100 Shares	10		82	82
Louisiana Intrastate Gas Company, L.L.C. (LIG)	900 Shares	90	(F)	111,638	111,638
LIG Chemical Company (LIGCHEM)	900 Shares	90		(6,993)	(6,993)
LIG Liquids Company, L.L.C. (LIGLIQ)	90 Shares	9	(G)	1,308	1,308
LIG Liquids Company, L.L.C. (LIGLIQ)	810 Shares	81	(G)	11,775	11,775
Tuscaloosa Pipeline Company (TUSCALOOSA)	900 Shares	90		740	740
AEP Energy Services Ventures, Inc. (VENTURES)	100 Shares	100		17,426	17,426
Ventures Lease Co., LLC	Shares	100		-	-
AEP Acquisition L.L.C. (AEPACQ)	Uncertificated	50	(H)	12,876	12,876
Jefferson Island Storage & Hub L.L.C. (JISH)	50 Shares	50		101,324	101,324
AEP Energy Services Ventures II, Inc. (VENTURES II)	10 Shares	100		17,433	17,433
AEP Acquisition L.L.C. (AEPACQ)	Uncertificated	50	(H)	12,876	12,876
Jefferson Island Storage & Hub L.L.C. (JISH)	50 Shares	50		101,324	101,324
AEP Energy Services Ventures III, Inc. (VENTURES III)	10 Shares	100		155,803	155,803
AEP Resources International, Ltd. (AEPRI)	2 Shares	100		37,712	37,721
AEP Pushan Power, LDC (PUSHAN)	99 Shares	99	(I)	37,374	37,374
Nanyang General Light Electric Co., Ltd. (NGLE)	(I)	69.3	(J)	96,244	96,200
AEP Resources Mauritius Company (MAURITIUS)	9,900 Shares	99	(I)	(20)	(20)
AEP Resources Project Management Company, Ltd. (AEPRPM)	1 Shares	100		377	363
AEP Pushan Power, LDC (PUSHAN)	1 Shares	1	(I)	377	377

ITEM 1. (CONTINUED)

Nanyang General Light Electric Co., Ltd. (NGLE)	(I)	0.7	(J)	972	971
AEP Resources Mauritius Company (MAURITIUS)	100 Shares	1	(I)	-	-
AEP Resource Services LLC	Uncertificated	100		879	879
Yorkshire Power Group Limited	176,000,000 Shares	40	(K)	308,000	268,943
Yorkshire Cayman Holding Limited	Shares	80		-	-
Yorkshire Holdings plc	50,000 Shares	80		-	-
Yorkshire Electricity Group plc	127,416,762 Shares	80		-	-
Yorkshire Power Finance Limited	16 Shares	1.6	(L)	-	-
Yorkshire Power Finance Limited	784 Shares	78.4	(L)	-	-
Total AEP Resources, Inc.				1,242,410	1,200,181
Appalachian Power Company* (APCo)	13,499,500 Shares	98.7		1,096,259	1,117,298
Cedar Coal Co. (CeCCo)	2,000 Shares	100		4,853	4,853
Central Appalachian Coal Company** (CACCo)	3,000 Shares	100		736	736
Central Coal Company** (CCCo)	1,500 Shares	50	(M)	604	604
Southern Appalachian Coal Company** (SACCo)	6,950 Shares	100		9,286	9,286
West Virginia Power Company** (WVPCo)	100 Shares	100		260	250
Total Appalachian Power Company				15,739	15,729
Columbus Southern Power Company (CSPCo)*	16,410,426 Shares	100		713,449	713,449
Colomet, Inc.** (COLM)	1,500 Shares	100		2,374	2,374
Conesville Coal Preparation Company (CCPC)	100 Shares	100		1,530	1,530
Simco Inc.** (Simco)	90,000 Shares	100		372	372
Ohio Valley Electric Corporation (OVEC)	4,300 Shares	4.3		513	430
Total Columbus Southern Power Company				4,789	4,706
Franklin Real Estate Company (FRECo)	100 Shares	100		30	28
Indiana Franklin Realty, Inc. (IFRI)	10 Shares	100		1	1
Indiana Michigan Power Company* (I&M)	1,400,000 Shares	100		793,099	800,286
Blackhawk Coal Company** (BHCCo)	39,521 Shares	100		55,965	55,965
Price River Coal Company** (PRCCo)	1,091 Shares	100		27	27
Total Indiana Michigan Power Company				55,992	55,992
Kentucky Power Company (KEPCo)	1,009,000 Shares	100		266,713	269,499
Kingsport Power Company (KGPCo)	410,000 Shares	100		23,119	23,775

ITEM 1. (CONTINUED)

Ohio Power Company* (OPCo)	27,952,473 Shares	99.2	1,181,771	1,186,183
Cardinal Operating Company (CdOpCo)	250 Shares	50 (N)	70	83
Central Coal Company** (CCCo)	1,500 Shares	50 (M)	604	604
Central Ohio Coal Company (COCCo)	69,000 Shares	100	10	10
Southern Ohio Coal Company (SOCCo)	5,000 Shares	100	55,333	55,334
Windsor Coal Company (WCCo)	4,064 Shares	100	51	223
Total Ohio Power Company			56,068	56,254
Ohio Valley Electric Corporation* (OVEC)	39,900 Shares	39.9	4,761	4,082
Indiana-Kentucky Electric Corporation (IKEC)	17,000 Shares	100 (O)	3,400	3,400
Central and South West Corporation (CSW)	Shares	100	3,666,665	3,666,567
Central Power and Light Company (CPL)	6,755,535 Shares	100	1,371,438	1,371,438
Public Service Company of Oklahoma (PSO)	9,013,000 Shares	100	477,699	477,699
Ash Creek Mining Company	383,904 Shares	100	7	7
Southwestern Electric Power Company (SWEPCo)	7,536,640 Shares	100	679,121	679,121
The Arklahoma Corporation	238 Shares	47.6	367	175
Southwestern Arkansas Utilities Corporation	100 Shares	100	10	10
West Texas Utilities Company (WTU)	5,488,560 Shares	100	264,652	264,652
CSW Leasing, Inc. (CSWL)	800 Shares	80	27,468	21,974
CSW Credit, Inc. (CREDIT)	246 Shares	100	55,415	55,415
C3 Communicatitons, Inc. (COMM)	1,000 Shares	100	(52,904)	(52,904)
CSWC Southwest Holdings, Inc.	100 Shares	100	1	1
CSWC TeleChoice Management, Inc.	100 Shares	100	1	1
CSWC TeleChoice, Inc.	100 Shares	100	1	1
CSW Energy, Inc. (CSWE)	1,000 Shares	100	172,862	172,862
CSW Development-I, Inc. (CSWD-I)	1,000 Shares	100	51,082	51,082
Polk Power GP II, Inc.	500 Shares	50	257	128
Polk Power GP, Inc.	1,000 Shares	100	273	273
Polk Power Partners, LP	Partnership	1 (U)	525	525
CSW Mulberry II, Inc.	1,000 Shares	100	25,142	25,142
CSW Mulberry, Inc.	1,000 Shares	100	26,644	26,644
Polk Power Partners, LP	Partnership	45.75 (U)	24,493	24,493
Mulberry Holdings, Inc.	1,000 Shares	100	1	1
Noah I Power GP, Inc.	1,000 Shares	100	(1)	(1)
Noah I Power Partners, LP	Partnership	1 (V)	188	189
Noah I Power Partners, LP	Partnership	94.5 (V)	16,930	17,033
Brush Cogeneration Partners	Partnership	50 (W)	34,422	17,211

ITEM 1. (CONTINUED)

Orange Cogeneration GP II, Inc.	500 Shares	50	(HH)	54	27
Orange Cogeneration GP Inc.	1,000 Shares	100		52	52
Orange Cogeneration Limited Partnership	Partnership	1	(X)	(111)	(111)
CSW Orange II, Inc.	1,000 Shares	100		839	839
CSW Orange, Inc.	1,000 Shares	100		2,923	2,923
Orange Cogeneration Limited Partnership	Partnership	49.5	(X)	(5,458)	(5,458)
Orange Cogen Funding Corp.	1,000 Shares	100		1	1
Orange Holdings, Inc.	1,000 Shares	100		1	1
CSW Development -II, Inc. (CSWD-II)	1,000 Shares	100		(3,999)	(3,999)
CSW Ft. Lupton, Inc. (CSWFL)	1,000 Shares	100		93,378	93,378
Thermo Cogeneration Partnership, LP	Partnership	50	(Y)	6,063	3,796
Newgulf Power Venture, Inc. (NEWGULF)	1,000 Shares	100		12,108	12,108
CSW Sweeny GP I, Inc. (SWEENY)	1,000 Shares	100		126	126
CSW Sweeny GP II, Inc.	1,000 Shares	100		552	552
CSW Sweeny LP I, Inc. (SWEENY)	1,000 Shares	100		9,875	9,875
CSW Sweeny LP II, Inc.	1,000 Shares	100		31,483	31,483
Sweeny Cogneration Limited Partnership	Partnership	50	(Z)	27,260	27,260
CSW Development-3, Inc. (CSWD#)	1,000 Shares	100		-	-
CSW Northwest GP, Inc.	1,000 Shares	100		-	-
CSW Northwest LP, Inc.	1,000 Shares	100		-	-
CSW Power Marketing, Inc.	1,000 Shares	100		-	-
CSW Nevada, Inc.	1,000 Shares	100		-	-
CSW Services International, Inc.	1,000 Shares	100		1,384	1,384
Diversified Energy Contractors Company, LLC	900 Shares	90		(28,193)	(28,193)
DECCO II LLC	1,000 Shares	100		0	0
Diversified Energy Contractors, LP	Partnership	1	(II)	(20)	(20)
Diversified Energy Contractors, LP	Partnership	99	(II)	(1,965)	(1,965)
Industry and Energy Associates, LLC	1,000 Shares	100		1,323	1,323
CSW Frontera GP I, Inc.	1,000 Shares	100		33	33
CSW Frontera GP II, Inc.	1,000 Shares	100		83	83
Frontera Generation Limited Partnership	Partnership	1	(JJ)	80	80
CSW Frontera LP I, Inc.	1,000 Shares	100		3,518	3,518
CSW Frontera LP II, Inc.	1,000 Shares	100		6,966	6,966
Frontera Generation Limited Partnership	Partnership	99	(JJ)	7,883	7,883
Frontera International Sales Limited	500 Shares	100		1	1
CSW Eastex GP I, Inc.	1,000 Shares	100		(1)	(1)
CSW Eastex GP II, Inc.	1,000 Shares	100		(11)	(11)
Eastex Cogeneration Limited Partnership	Partnership	1	(KK)	(17)	(17)
CSW Eastex LP I, Inc.	1,000 Shares	100		(66)	(66)
CSW Eastex LP II, Inc.	1,000 Shares	100		(1,079)	(1,079)
Eastex Cogeneration Limited Partnership	Partnership	99	(KK)	(1,726)	(1,726)
Southwestern Electric Wholesale Company	1,000 Shares	100		0	0

ITEM 1. (CONTINUED)

CSW International, Inc. (CSWI)	1,000 Shares	100		802,552	802,552
CSW International Two, Inc. (CSWI2)	1,000 Shares	100		1,035,666	1,035,666
CSW UK Holdings	427,275,004 Shares	100		637,922	637,922
CSWI Europe Limited	1,000 Shares	100		2,140	2,140
South Coast Power Limited	1 Shares	50		-	-
Shoreham Operations Company Limited	2 Shares	50		-	-
CSW UK Finance Company	384,547,502 Shares	90	(CC)	640,408	576,367
CSW Investments	629,842,502 Shares	83.7	(DD)	1,013,441	942,500
SEEBOARD Group plc	811,194 Shares	83.7		1,151,781	1,151,781
SEEBOARD (Generation) Limited	837 Shares	83.7		11,914	11,914
Medway Power Limited	1,178 Shares	31.4	(EE)	28,382	10,643
SEEBOARD Natural Gas Limited	1.7 Shares	83.7		(1,353)	(1,353)
Beacon Gas Limited	5,022,000 Shares	83.7		(5,336)	(5,336)
CSW UK Limited	1.7 Shares	83.7		-	-
Power Networkd Limited	1.7 Shares	83.7		-	-
SEEBOARD plc	209,663,229 Shares	83.7		653,056	653,056
Appliance Protect Limited	1.7 Shares	83.7		-	-
Direct Power Limited	1.7 Shares	83.7		-	-
Directricity Limited	1.7 Shares	83.7		-	-
Electricity (UK) Limited	1.7 Shares	83.7		-	-
Electricity 2000 Limited	1.7 Shares	83.7		-	-
Energy Express Limited	1.7 Shares	83.7		-	-
First Electricity Limited	1.7 Shares	83.7		-	-
First Gas Limited	1.7 Shares	83.7		-	-
Gas 2000 Limited	1.7 Shares	83.7		-	-
Home Electricity Company Limited	1.7 Shares	83.7		-	-
Home Energy Company Limited	1.7 Shares	83.7		-	-
Home Gas Company Limited	1.7 Shares	83.7		-	-
Home Power Company Limited	1.7 Shares	83.7		-	-
Horizon Natural Gas Limited	1.7 Shares	83.7		-	-
Light & Power (UK) Limited	1.7 Shares	83.7		-	-
Longfield Insurance Company Limited	418,500 Shares	83.7		1,122	1,122
Powercare Limited	1.7 Shares	83.7		-	-
Premier Electricity Limited	1.7 Shares	83.7		-	-
Premier Utilities Limited	1.7 Shares	83.7		-	-
Seeb Limited	8,370 Shares	83.7		19	19
SEEBOARD Employment Services Limited	1.7 Shares	83.7		814	814
SEEBOARD Insurance Company Limited	837,000 Shares	83.7		10,433	10,433
SEEBOARD Final Salary Pension Plan				-	-
Trustee Company Limited	1.7 Shares	83.7		-	-
SEEBOARD International Limited	418,500 Shares	83.7		880	880
SEEBOARD Pension Investment Plan Trustee Company Limited	1.7 Shares	83.7		-	-
SEEBOARD Share Scheme Trustees Limited	1.7 Shares	83.7			-

ITEM 1. (CONTINUED)

SEEBOARD Trading Limited	8,370,002 Shares	83.7		27,525	27,525
SEEPOWER Limited	8,370 Shares	83.7		(5,147)	(5,147)
SEEBOARD Metering Limited	8,370 Shares	83.7		-	-
Power Asset Development Company Limited	42 Shares	41.9	(FF)	-	212
SEEBOARD Powerlink Limited	669,600 Shares	67.0	(GG)	11,586	9,269
Selectricity Limited	1.7 Shares	83.7		-	-
South Eastern Electricity Board Limited	1.7 Shares	83.7		-	-
South Eastern Electricity Limited	1.7 Shares	83.7		-	-
South Eastern Services Limited	1.7 Shares	83.7		-	-
South Eastern Utilities Limited	1.7 Shares	83.7		-	-
Southern Gas Limited	418,500 Shares	83.7		(10,096)	(10,096)
Torch Natural Gas Limited	1.7 Shares	83.7		-	-
UK Electricity Limited	1.7 Shares	83.7		-	-
UK Light and Power Limited	1.7 Shares	83.7		-	-
CSW International Three, Inc.	1,000 Shares	100		-	-
CSW UK Investments Limited	100 Shares	100		-	-
CSW UK Finance Company	42,727,500 Shares	10	(CC)	71,156	64,041
CSW Investments	69,982,500 Shares	9.3	(DD)	112,605	104,722
SEEBOARD Group plc	90,133 Shares	9.3		127,976	127,976
SEEBOARD (Generation) Limited	90 Shares	9.3		1,324	1,324
Medway Power Limited	131 Shares	3.5	(EE)	3,164	1,186
SEEBOARD Natural Gas Limited	0.2 Shares	9.3		(150)	(150)
Beacon Gas Limited	558,000 Shares	9.3		(593)	(593)
CSW UK Limited	0.2 Shares	9.3		-	-
Power Networkd Limited	0.2 Shares	9.3		-	-
SEEBOARD plc	23,295,914 Shares	9.3		72,562	72,562
Appliance Protect Limited	0.2 Shares	9.3		-	-
Direct Power Limited	0.2 Shares	9.3		-	-
Directricity Limited	0.2 Shares	9.3		-	-
Electricity (UK) Limited	0.2 Shares	9.3		-	-
Electricity 2000 Limited	0.2 Shares	9.3		-	-
Energy Express Limited	0.2 Shares	9.3		-	-
First Electricity Limited	0.2 Shares	9.3		-	-
First Gas Limited	0.2 Shares	9.3		-	-
Gas 2000 Limited	0.2 Shares	9.3		-	-
Home Electricity Company Limited	0.2 Shares	9.3		-	-
Home Energy Company Limited	0.2 Shares	9.3		-	-
Home Gas Company Limited	0.2 Shares	9.3		-	-
Home Power Company Limited	0.2 Shares	9.3		-	-
Horizon Natural Gas Limited	0.2 Shares	9.3		-	-
Light & Power (UK) Limited	0.2 Shares	9.3		-	-
Longfield Insurance Company Limited	46,500 Shares			-	-
Powercare Limited	0.2 Shares	9.3		-	-
Premier Electricity Limited	0.2 Shares	9.3		-	-

ITEM 1. (CONTINUED)

Premier Utilities Limited	0.2 Shares	9.3		-	-
Seeb Limited	930 Shares	9.3		2	2
SEEBOARD Employment Services Limited	0.2 Shares	9.3		-	-
SEEBOARD Insurance Company Limited	93,000 Shares	9.3		1,159	1,159
SEEBOARD Final Salary Pension Plan				-	-
Trustee Company Limited	0.2 Shares	9.3		-	-
SEEBOARD International Limited	46,500 Shares	9.3		98	98
SEEBOARD Pension Investment Plan Trustee Company Limited	0.2 Shares	9.3		-	-
SEEBOARD Share Scheme Trustees Limited	0.2 Shares	9.3		-	-
SEEBOARD Trading Limited	930,000 Shares	9.3		3,058	3,058
SEEPOWER Limited	930 Shares	9.3		(572)	(572)
Meterpoint Limited	930 Shares	9.3		-	-
Power Asset Development Company Limited	5 Shares	4.7	(FF)	48	24
SEEBOARD Powerlink Limited	74,400 Shares	7.4	(GG)	1,280	1,024
Selectricity Limited	0.2 Shares	9.3		-	-
South Eastern Electricity Board Limited	0.2 Shares	9.3		-	-
South Eastern Electricity Limited	0.2 Shares	9.3		-	-
South Eastern Services Limited	0.2 Shares	9.3		-	-
South Eastern Utilities Limited	0.2 Shares	9.3		-	-
Southern Gas Limited	46,500 Shares	9.3		(1,122)	-
Torch Natural Gas Limited	0.2 Shares	9.3		-	-
UK Electricity Limited	0.2 Shares	9.3		-	-
UK Light and Power Limited	0.2 Shares	9.3		-	-
CSW Investments	52,675,000 Shares	7	(DD)	78,823	78,823
SEEBOARD Group plc	67,842 Shares	7		96,326	96,326
SEEBOARD (Generation) Limited	70 Shares	7		996	996
Medway Power Limited	98 Shares	2.6	(EE)	2,350	881
SEEBOARD Natural Gas Limited	0.1 Shares	7		(113)	(113)
Beacon Gas Limited	420,000 Shares	7		(446)	(446)
CSW UK Limited	0.1 Shares	7		-	-
Power Networkd Limited	0.1 Shares	7		-	-
SEEBOARD plc	17,534,559 Shares	7		54,616	54,616
Appliance Protect Limited	0.1 Shares	7		-	-
Direct Power Limited	0.1 Shares	7		-	-
Directricity Limited	0.1 Shares	7		-	-
Electricity (UK) Limited	0.1 Shares	7		-	-
Electricity 2000 Limited	0.1 Shares	7		-	-
Energy Express Limited	0.1 Shares	7		-	-
First Electricity Limited	0.1 Shares	7		-	-
First Gas Limited	0.1 Shares	7		-	-
Gas 2000 Limited	0.1 Shares	7		-	-

ITEM 1. (CONTINUED)

Home Electricity Company Limited	0.1 Shares	7		-	-
Home Energy Company Limited	0.1 Shares	7		-	-
Home Gas Company Limited	0.1 Shares	7		-	-
Home Power Company Limited	0.1 Shares	7		-	-
Horizon Natural Gas Limited	0.1 Shares	7		-	-
Light & Power (UK) Limited	0.1 Shares	7		-	-
Longfield Insurance Company Limited	35,000 Shares	7		94	-
Powercare Limited	0.1 Shares	7		-	-
Premier Electricity Limited	0.1 Shares	7		-	-
Premier Utilities Limited	0.1 Shares	7		-	-
Seeb Limited	700 Shares	7		2	2
SEEBOARD Employment Services Limited	0.1 Shares	7		68	68
SEEBOARD Insurance Company Limited	70,000 Shares	7		873	873
SEEBOARD Final Salary Pension Plan				-	-
Trustee Company Limited	0.1 Shares	7		-	-
SEEBOARD International Limited	35,000 Shares	7		74	74
SEEBOARD Pension Investment Plan Trustee Company Limited	0.1 Shares	7		-	-
SEEBOARD Share Scheme Trustees Limited	0.1 Shares	7		-	-
SEEBOARD Trading Limited	700,000 Shares	7		2,302	2,302
SEEPOWER Limited	700 Shares	7		(430)	(430)
Meterpoint Limited	700 Shares	7		-	-
Power Asset Development Company Limited	4 Shares	3.5	(FF)	35	18
SEEBOARD Powerlink Limited	56,000 Shares	5.6	(GG)	968	775
Selectricity Limited	0.1 Shares	7		-	-
South Eastern Electricity Board Limited	0.1 Shares	7		-	-
South Eastern Electricity Limited	0.1 Shares	7		-	-
South Eastern Services Limited	0.1 Shares	7		-	-
South Eastern Utilities Limited	0.1 Shares	7		-	-
Southern Gas Limited	35,000 Shares	7		(844)	(844)
Torch Natural Gas Limited	0.1 Shares	7		-	-
UK Electricity Limited	0.1 Shares	7		-	-
UK Light and Power Limited	0.1 Shares	7		-	-
CSW International (U.K.), Inc.	100 Shares	100		0	0
Energia Internacional de CSW, SA de CV ****	23,564,706 Shares	100		2,962	2,962
Aceltek, S. de R.L. de C.V. ****	Partnership	50	(AA)	-	-
Enertek, S.A. de C.V. ****	4,549,085 Shares	100		-	-
Cinergy, S. de R.L. de C.V. ****	Partnership	100		-	-
Servicios Industriales y Administrativos del Noroeste, S. de R.L. de C.V. (SIAN) ****	Partnership	51	(BB)	-	-
CSW International, Inc.	1,000 Shares	100		166,595	166,595

ITEM 1. (CONTINUED)

CSW Vale L.L.C.	1,000	99.9	169,271	169,271
Empresa de Electricidade Vale de Paranapanema S.A. ****	21,498,447 Shares	21.42	-	-
CSW Power do Brasil ltda. ****	LLC	100	-	-
Latin American Energy Holdings, Inc. ****	1,000 Shares	10	-	-
Chile Energy Holdings L.L.C. ****	1,000 Shares	90	-	-
Inversiones Sol Energia Chile Limitada	LLC	100	83,786	83,786
Sol Energia Holdings I, Limitada ****	LLC	100	-	-
Sol Energia Holdings II, Limitada ****	LLC	100	-	-
Sol Energia, Limitada ****	LLC	100	-	-
CSW International Energy Development Ltd. ****	LLC	100	-	-
Tenaska CSW International Ltd. ****	1,000	50	-	-
Enershop Inc. (Enershop)	1,000 Shares	100	(15,981)	(15,981)
Envirotherm, Inc.	1,500 Shares	100	-	-
CSW Energy Services, Inc. (ESI)	1,000 Shares	100	(23,514)	(23,514)
Nuvest, L.L.C.	1,714,000 Shares	92.9	(2,375)	(1,852)
National Temporary Services, Inc.	1,000 Shares	100	-	-
Octagon Inc.	1,000 Shares	100	(4,884)	(4,884)
Numanco, L.L.C.	1,000 Shares	100	(5,665)	(5,665)
Power Systems Energy Services, Inc.	1,000 Shares	100	180	180
NuSun, Inc.	1,000 Shares	100	7,783	7,783
Sun Technical Services, Inc.	50 Shares	100	7,677	7,677
Calibration Testing Corporation	6,480 Shares	100	106	106
ESG Technical Services, L.L.C.	10,000 Shares	100	-	-
ESG Manufacturing, L.L.C.	1,000 Shares	100	708	708
National Environmental Services Technology L.L.C.	100,000 Shares	100	267	267
ESG Indonesia, L.L.C.	100,000 Shares	100	-	-
Advance Shielding Technologies, L.L.C.	50 Shares	50	-	-
ESG, L.L.C.	500 Shares	50	(764)	(382)
Wheeling Power Company (WPCo)	150,000 Shares	100	26,746	27,727
Equity in Subsidiaries - Unallocated			8,889	8,889

ITEM 1. (CONTINUED)

New subsidiaries added during 2000 are:

Name of Company	Date and Place of Organization	Description of Business
AEP Energy Services GmbH	March 17, 2000 - Germany	Energy Trading
AEP Energy Services (Switzerland) GmbH	June 19, 2000 - Switzerland	Energy Trading
AEP Fiber Venture, LLC	March 29, 2000 - State of Virginia	Telecommunication and Development of Fiber Network
Datapult, LLC	November 29, 2000 - State of Delaware	Produce and Sell Energy Management Services
Datapult Limited Partnership	December 11, 2000 - State of Delaware	Produce and Sell Energy Management Services
AEP Retail Energy, LLC	June 28, 2000 - State of Delaware	Retail Energy Sales
AEP Resources Services, LLC	October 20, 1999 - State of Delaware	Investment in Electric Power Technology
Energica de Mexicali, S de R.L. de C.V.	February 4, 1999 - Mexico	Own and Finance Foreign Electric Projects and Energy Trading
America's Fiber Network, LLC		Telecommunication and Development of Fiber Network
America's Fiber Touch, LLC	January 5, 2000 - Delaware	Telecommunication and Development of Fiber Network
AEP Resources do Brasil Ltda.	November 26, 1998 - Brazil	Invest in Foreign Electric Projects
Ventures Lease Co., LLC	May 2, 2000 - Delaware	Equipment Leasing
Compresion Baijo S de R.L. de C.V.		Foreign Electric Project

(A) Name changed from AEP Resources Service Company on March 7, 2000.
(B) AEPR Global Investments BV owns 0.3% and AEPR Global Ventures B.V. owns 99.97%.
(C) AEP Resources Global Ventures B.V. owns 16% and the remaining 84% is owned an unaffiliated company.
(D) Owned 99% by AEP Resources CitiPower I Pty Ltd and 1% by AEP Resources CitiPower II Pty Ltd.
(E) Owned 20% by AEP Resources Australia Pty., Ltd. and 80% by unaffiliated companies.
(F) Owned 10% by LIG, Inc. and 90% by LIG Pipeline Company.
(G) Owned 10% by LIG Chemical Company and 90% by Louisiana Intrastate Gas Company.
(H) Owned 50% by AEP Resources Ventures, Inc and 50% by AEP Resources Ventures II, Inc.
(I) Owned 99% by AEP Resources International Ltd. and 1% by AEP Resources Project Management Company Ltd.
(J) AEP Pushan Power, LDC owns 70%; the other 30% is owned by unaffiliated companies. The Company is a joint venture company domiciled in the People's Republic of China. It has registered capital totaling Renminbi four hundred seventy six million six hundred sixty seven thousand Yuan.
(K) AEP Resources, Inc. owns 40% and AEP Holdings I CV owns 10%. The remaining 50% is owned by an unaffiliated company.
(L) Owned 2% by Yorkshire Holdings plc and 98% by Yorkshire Power Group Limited.
(M) Owned 50% by Appalachian Power Company and 50% by Ohio Power Company.
(N) Ohio Power Company owns 50% of the stock; the other 50% is owned by a corporation not affiliated with American Electric Power Company, Inc.
(O) This Company is a wholly-owned subsidiary of Ohio Valley Electric Corporation, 44.2% of whose voting securities are owned by the American Electric Power System, the balance by unaffiliated companies.

(P) Includes unsecured debt as follows: for AEHOL - $182,729,000, AEPRA - $4,192,000, AEPRGH - $243,600,000, AEPSC - $1,100,000, NGLE - $56,222,000, CdOpCo - $83,000 and MAURITIUS - $1,065,000.
(Q) AEP Communications, LLC and C3 Communications own 49.75% each, Datapult, LLC owns .5% of Partnership.
(R) Owned 48% by AEP Fiber Ventures LLC and the remaining 52% is owned by unaffiliated companies.
(S) Owned 50% by AEP Communications, LLC and the remaining 50% is owned by an unaffiliated company.
(T) Owned 99.9% by AEP Resources, Inc. and .1% by AEP Delaware Investment Company II.
(U) CSW Mulberry, Inc. holds a 45.75% interest and Polk Power GP, Inc. holds a 1% interest.
(V) CSW Development-I, Inc. holds a 94.5% interest and Noah I Power GP, Inc. holds a 1% interest.
(W) Noah I Power Partners, L.P. holds a 50% interest and 50% by non-affiliates.
(X) CSW Orange, Inc. holds a 49.5% interest and Orange Cogeneration G.P., Inc. holds a 1% interest.
(Y) CSW Ft. Lupton, Inc. holds a 50% interest.
(Z) CSW Sweeney LP II, Inc. holds a 49% interest and CSII Sweeney GPH, Inc. holds a 1% interest. The remaining 50% interest is held by unaffiliated companies.

(AA) Energia Internacional de CSW, S.A. de C.V. owns 49.99% of Aceltek, S. de R.L. de C.V.
(BB) Enertek, S.A. de C.V. owns 51.12% of Servicios Industriales y Administrativos del Noreste, S. de R.L. de C.V.
(CC) CSW UK Holding holds a 90% interest and cSW International Three, Inc. holds a 10% interest.
(DD) CSW UK Finance Company holds a 93% interest and CSW International Three, Inc. holds a 7% interest.
(EE) SEEBOARD (Generation) Limited holds a 37.5% interest and the remaining 62.5% interest is held by unaffiliated companies.
(FF) SEEBOARD Limited holds a 50% interest and the remaining 50% interest is held by an unaffiliated companies.
(GG) SEEBOARD Limited holds an 80% interest and the remaining 20% interest is held by unaffiliated companies.
(HH) CSW Development-I, Inc. holds 50% of the stock and the remaining 50% is held by unaffiliated companies.
(II) Diverwsified Energy Contractors Company, LLC holds a 99% interest and DECCO II LLC holds a 1% interest.
(JJ) CSW Frontera LP II, Inc. holds a 99% interest and CSW Frontera CP-II, Inc. holds a 1% interest.
(KK) CSW Eastex LP II, Inc. holds a 99% interest and CSW Eastex GP II, Inc. holds a 1% interest.

*Exempt under Section 3(A) pursuant to Rule 2 thereof.
**Inactive.
***Exempt under Securities and Exchange Commission Release No. 35-24295.
****Information not currently available.

ITEM 2. ACQUISITIONS OR SALES OF UTILITY ASSETS

Name of Company	Consideration	Brief Description of Transaction	Location	Exemption
Columbus Southern Power	1,284,000	Substation #77 facilities	Substation #77	Rule 44

ITEM 3. ISSUE, SALE, PLEDGE, GUARANTEE OR ASSUMPTION OF SYSTEM SECURITIES

Name of Issuer and Description of Issues (1)	Date and Form of Transactions (2)	Consideration (3) (in thousands)	Authorization or Exemption (4)
Appalachian Power Company:			
Floating Rate Notes, Series A, Due 2001	6/27/2000 - Public Offering	74,888	Rule 52
Central Power and Light Company:			
Floating Rate Notes, Due February 22, 2002	2/23/2000 - Public Offering	149,625	Rule 52
Indiana Michigan Power Company:			
Floating Rate Notes, Series B, Due 2002	08/31/2000 - Public Offering	199,500	Rule 52

ITEM 3. (CONTINUED)

Name of Issuer and Description of Issues (1)	Date and Form of Transactions (2)	Consideration (3) (in thousands)	Authorization or Exemption (4)
Kentucky Power Company:			
Floating Rate Notes, Series B, Due 2002	11/17/2000 - Public Offering	69,825	Rule 52
Ohio Power Company:			
Floating Rate Notes, Series A, Due 2001	5/22/2000 - Public Offering	74,888	Rule 52
Public Service Company of Oklahoma:			
Floating Rate Notes, Series A, Due 2002	11/21/2000 - Public Offering	105,735	Rule 52
Southwestern Electric Power Company:			
Floating Rate Notes, Due March 1, 2002	3/01/2000 - Public Offering	149,625	Rule 52

GUARANTEE:

At December 31, 2000, American Electric Power Company, Inc. had outstanding parental guaranties of approximately $1.9 billion.

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
American Electric Power Service Corp:				
Mortgage Notes				
9.60% Series Due 2008	AEPSC	2,000	EXT	Rule 42
AEP Communications, LLC:				
Notes Payable				
Variable - Due 2002	AEPC	60,000	EXT	Rule 42
AEP Resources, Inc.:				
Notes Payable				
Variable - Due 2000	AEPR	200,000	EXT	Rule 42
Variable - Due 2000	AEPR	355,000	EXT	Rule 42
Variable - Due 2000	AEPR	70,000	EXT	Rule 42
Appalachian Power Company:				
Cumulative Preferred Stock, No Par Value				
4-1/2% Series	APCo	468	EXT	Rule 42
5.90% Series	APCo	1,006	EXT	Rule 42
6.85% Series	APCo	8,450	EXT	Rule 42
First Mortgage Bonds				
6.35% Series Due 2000	APCo	48,000	EXT	Rule 42
6.71% Series Due 2000	APCo	48,000	EXT	Rule 42
7.125% Series Due 2024	APCo	4,600	EXT	Rule 42
8.00% Series Due 2025	APCo	4,963	EXT	Rule 42
Central Power and Light Company:				
First Mortgage Bonds				
6.00% Series HH Due 2000	CPL	100,000	EXT	Rule 42
7.50% Series AA Due 2020	CPL	50,000	EXT	Rule 42
Junior Debentures				
8.00% Series A Due 2037	CPL	1,500	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
CitiPower:				
Notes Payable				
Variable - Due 2000	Citipower	242,840	EXT	Rule 42
Columbus Southern Power Company:				
Cumulative Preferred Stock,				
No Par Value				
7.00% Series	CSPCo	10,000	EXT	Rule 42
First Mortgage Bonds				
7.25% Series Due 2002	CSPCo	18,395	EXT	Rule 42
6.80% Series Due 2003	CSPCo	4,903	EXT	Rule 42
8.40% Series Due 2022	CSPCo	1,976	EXT	Rule 42
Indiana Michigan Power Company:				
Cumulative Preferred Stock,				
$100 Par Value				
4-1/8% Series	I&M	225	EXT	Rule 42
4.12% Series	I&M	89	EXT	Rule 42
First Mortgage Bonds				
6.40% Series Due 2000	I&M	48,000	EXT	Rule 42
Senior Unsecured Notes Payable				
Floating - Due 2000	I&M	100,000	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Kentucky Power Company:				
Senior Unsecured Notes Payable Floating - Due 2000	KPCo	80,000	EXT	Rule 42
Notes Payable 6.57% Due 2000	KPCo	25,000	EXT	Rule 42
Kingsport Power Company:				
Notes Payable 6.73% Due 2000	KGPCo	5,000	EXT	Rule 42
Ohio Power Company:				
Cumulative Preferred Stock, $100 Par Value				
4-1/2% Series	OPCo	138	EXT	Rule 42
4.20% Series	OPCo	17	EXT	Rule 42
4.40% Series	OPCo	27	EXT	Rule 42
First Mortgage Bonds				
6.75% Series Due 2003	OPCo	1,155	EXT	Rule 42
7.10% Series Due 2023	OPCo	2,742	EXT	Rule 42
7.30% Series Due 2024	OPCo	3,272	EXT	Rule 42
Senior Unsecured Notes Payable 6.24% Due 2008	OPCo	11,817	EXT	Rule 42
Public Service Company of Oklahoma:				
First Mortgage Bonds				
5.89% Series Due 2000	PSO	10,000	EXT	Rule 42
6.43% Series Due 2000	PSO	10,000	EXT	Rule 42
Cumulative Preferred Stock $100 Par Value				
4.00% Series	PSO	3	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Southwestern Electric Power Company:				
First Mortgage Bonds				
5.25% Series AA Due 2000	SWEPCo	45,000	EXT	Rule 42
6.20% Series 1976A Due 2006	SWEPCo	145	EXT	Rule 42
Cumulative Preferred Stock				
$100 Par Value				
5.00% Series	SWEPCo	1	EXT	Rule 42
West Texas Utilities Company:				
First Mortgage Bonds				
7.50% Series T Due 2000	WTU	40,000	EXT	Rule 42
6.375% Series U Due 2005	WTU	8,000	EXT	Rule 42

ITEM 5. INVESTMENTS IN SECURITIES OF NONSYSTEM COMPANIES AS OF DECEMBER 31, 2000.

1. Aggregate amount of investments in persons operating in the retail service area of AEP or of its subsidiaries.

Name of Company (1)	Aggregate Amount of Investments in Persons (Entities), Operating in Retail Service Area of Owner (2) (in thousands)	Number of Persons (Entities) (3)	Description of Persons (Entities) (4)
APCo	$ 701	8	Industrial Development Corporations
AEPCLLC	(4,678)	2	Personal Communications Services Provider
AEPINV	1,314	1	Economic Development Company
AEPINV	100	1	Economic Development Company
I&M	8	1	Economic Development Company
WPCo	13	1	Industrial Development Corporation

2. Securities owned not included in 1 above.

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
AEPINV	Intersource Technologies, Inc.	Research & Technology Development	Common Stock Preferred Stock	800,000 95,000	9.9	$11,500
AEPINV	EnviroTech Investment Fund I	Research & Technology Development	Limited Partner	*	9.9	2,535
AEPINV	Altra Energy Technologies, Inc.	Internet-based Energy Trading	Convertible Preferred Stock	952,381	**	5,000
AEPPRO	Lectrix LLC	Provide Services-Power Quality	Limited Liability Company	***	33.3	524
AEPPRO	Lectrix LLC	Provide Services-Power Quality	Limited Liability Company	***	33.3	461
AEPPRO	Powerspan Corp.	Research & Technology Development	Convertible Preferred Stock	5,369,851	9.8	5,000

ITEM 5. (CONTINUED)
2. Securities owned not included in ITEM 1 (Continued).

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
AEPPRO	IntercontinentalExchange LLC	Trading platform for Electric Utilities	Limited Liability Company	***	5.3	3,167
AEP	Integrated Communications System, Inc.	Development of Demand Side Management	Common Stock	80,000	8.4	-
AEPINV	Pantellos Corporation	Internet-based Supply Chain	Common Stock	540,000	5.0	4,439
AEPINV	Active Power, Inc.	Research & Technology Development	Common Stock	37,501	4.0	513
C3 Comm	Infinitec Networks, Inc.	Local telecommunication services	Convertible Preferred Stock Series C	1,724,447	12.6	1,843
C3 Comm	Infinitec Networks, Inc.	Local telecommunication services	Convertible Preferred Stock Series D	13,984	.1	1,398
C3 Comm	Infinitec Networks, Inc.	Local telecommunication services	Warrants & Options	1,714,243	N/A	-
Seeboard plc	Electricity Pension Trustee Limited	Trustee Company	Common Stock	20,000	4.9	29,860
Seeboard plc	ESN Holdings Limited	Trustee Company	Common Stock	104	4.9	155
Seeboard plc	ESN Holdings Limited	Trustee Company	Preference shares	50,000	N/A	74,650
PSO	Powerware Solutions, Inc	Supplier of demand-side management software	Convertible Preferred Stock Series A, Voting	18,833	2.68	1,575
			Series A, Non-voting	263,033		

ITEM 5. (CONTINUED)
2. Securities owned not included in ITEM 1 (Continued).

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
PSO	AEMT, Inc	Manufacturer and sells residential surge protectors and power quality devices for industrial customers	Preferred Stock Series 1, Nonvoting	250,000	N/A	322
PSO	AEMT, Inc	Manufacturer and sells residential surge protectors and power quality devices for industrial customers	Preferred Stock Series 1, Nonvoting	781,250	N/A	1,573
PSO	Utility Data Resources, Inc	Provides utility outsourcing of large customer time differentiated meter reading and billing.	Convertible Preferred Stock Series A, Non-voting	16,175	4.5	1,617
			Common Stock Non-voting	257,500		
			Voting Common Stock	12,500		
PSO	RIKA Management Company, LLC	Engaged in the development and commercialization of computer automation technology for the electric power industry	Membership Units	50	4.0	1,918

ITEM 5. (CONTINUED)
2. Securities owned not included in ITEM 1 (Continued).

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
PSO	RIKA Management Company, LLC	Engaged in the development and commercialization of computer automation technology for the electric power industry	Membership Units	48	4.0	
PSO	RIKA Management Company, LLC	Engaged in the development and commericalization of computer automation technology for the electric power industry	Membership Units	71	4.0	-
PSO	RIKA Management Company, LLC	Engaged in the development and commericalization of computer automation technology for the electric power industry	Membership Units	48	4.0	

* Limited Partnership Interests
** Less than 3%
*** One-third Membership Interest

ITEM 6. OFFICERS AND DIRECTORS
PART I as of December 31, 2000

The following are the abbreviations to be used for principal business address and positions.

Principal Business Address	Code
1 Riverside Plaza Columbus, OH 43215	(a)
40 Franklin Road Roanoke, VA 24022	(b)
700 Morrison Road Gahanna, OH 43230	(c)
One Summit Square Fort Wayne, IN 46801	(d)
555 Office Center Place Gahanna, OH 43230	(e)
Dayuan Zhuan Village Pushan Town, Nanyang City People's Republic of China	(f)
Walker House, Mary Street P.O. Box 265GT George Town, Grand Cayman Cayman Islands	(g)
1105 North Market Street Wilmington, DE 19899	(i)
600 Bourke Street Melbourne, Victoria 3000 Australia	(j)
29/30 St. James's Street, London SW1A 1HB, Great Britain	(k)
P.O. Box B Brilliant, OH 43913	(l)
301 Cleveland Ave., SW Canton, OH 44702	(m)
225 South 15th Street Philadelphia, PA 19102	(n)
Wetherby Road, Scarcroft, Leeds LS14 3HS Great Britain	(o)
P.O. Box 309 George Town Grand Cayman, Cayman Islands	(p)
Herengracht 548 1017 CG Amsterdam The Netherlands	(q)
Suite 400, Deseret Building Salt Lake City, UT 84111	(r)
1701 Central Avenue Ashland, KY 41101	(s)
301 Virginia Street East Charleston, WV 25301	(t)
P.O. Box 75 Wheeling, WV 26003	(u)
P.O. Box 468 Piketon, Ohio 45661	(w)
1225 17th Street, Suite 500 Denver, CO 80202	(x)
474 Flinders Street Melbourne, Victoria 3000 Australia	(aa)
5555 San Felipe Houston, TX 77056	(bb)
461 Rua Butana, 4th Fl. Rm A Sao Paulo, Sao Paulo 05424-140 Brazil	(cc)
Level 15, 624 Bourke Street Melbourne, Victoria 3000 Australia	(dd)
Bahnstrasse 16, 40212 Dusseldorf, Germany	(ee)
Interpark House, 7 Down St. Mayfair London W1Y 7DS Great Britain	(ff)
1010 Wien, Austria	(gg)
Alpenstrasse 12 CH-6304 Zug, Switzerland	(hh)
130 N. Main Street Butte, MT 59701	(ii)
212 E. 6th Street Tulsa, OK 74119	(jj)
539 N. Carancahua Street Corpus Christi, TX 78401	(kk)
1616 Woodall Rodgers Fwy Dallas, TX 75202	(ll)
Forest Gate, Brighton Road Crawley, West Sussex RH11 9BH Great Britain	(mm)
P.O. Box 806E Bridgetown, Barbados	(nn)
Strawinskylaan 3105,1077 ZX Amsterdam, The Netherlands	(oo)
Torre Chapultepec Piso 13 Ruben Dario, No.281, Bosques de Chapultepec 11580 Mexico, D.F.	(pp)
212 East 6th Street Tulsa, OK 74119	(qq)
428 Travis Street Shreveport, LA 71156	(rr)
301 Cypress Street Abilene, TX 79601	(ss)

Position	Code
Director	D
Chairman of the Board	CB
Vice Chairman of the Board	VCB
President	P
Chief Executive Officer	CEO
Chief Operating Officer	COO
Executive Vice President	EVP
Senior Vice President	SVP
Vice President	VP
Controller	C
Deputy Controller	DC
Secretary	S
Treasurer	T
General Counsel	GC
Chief Financial Officer	CFO
Chief Accounting Officer	CAO
Chief Information Officer	CIO
Managing Director	MD
Board of Managers	B
Delegate Manager	DM
General Manager	GM

The officer's or director's principal business address is the same as indicated in the Company heading unless another address is provided with the individual's name.

American Electric Power Company, Inc.

Name and Principal Address(a)	Position
E. R. Brooks 7 Glenmeadow Court Dallas, TX 75225	D
Donald M. Carlton 403 N. Weston Lane Austin, TX 78733	D
John P. DesBarres 32064 Pacifica Drive Rancho Palos Verdes, CA 90275	D
E. Linn Draper, Jr.	D,CB,P,CEO
Robert W. Fri 6001 Overlea Road Bethesda, MD 20816	D
William R. Howell 4 Saint Andrews Court Frisco, TX 75034	D
Lester A Hudson, Jr. P.O. Box 8583 Greenville, SC 29604	D
Leonard J. Kujawa 225 Peachtree St.,NE Atlanta, GA 30303	D
James L. Powell Box 98 Fort McKavett, TX 76841	D
Richard L. Sandor 111 W. Jackson Blvd., 14th FL. Chicago, IL 60604	D
Thomas V. Shockley, III	D,VCB
Donald G. Smith P.O. Box 13948 Roanoke, VA 24038	D
Linda Gillespie Stuntz 1275 Pennsylvania Ave.,NW Washington, DC 20004	D
Kathryn D. Sullivan 795 Old Oak Trace Columbus, OH 43235	D
Morris Tanenbaum 74 Falmouth Street Short Hills, NJ 07078	D
Henry W. Fayne	VP,CFO
Leonard V. Assante	DC
Armando A. Pena	T
Susan Tomasky	S

AEI (Loy Yang) Pty Ltd

Name and Principal Address(j)	Position
Alan John Bielby 147 Argyle Street Kowloon, Hong Kong	D
Donald E. Boyd (a)	D
Peter Albert Littlewood 22/F,CMG Asia Tower The Gateway Harbour City 15 Canton Road Kowloon, Hong Kong	D
Kenneth Warren Oberg 22/F,CMG Asia Tower The Gateway Harbour City 15 Canton Road Kowloon, Hong Kong	D
Paul Robert Rainey	D,S

AEP Acquisition, L.L.C.

Name and Principal Address(a)	Position
Paul D. Addis	CB
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Leonard V. Assante	C
Timothy A. King	S

AEP Communications, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
Donald M. Clements, Jr.	D,P
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
William J. Lhota	D
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Peter R. Thomas	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Communications, LLC

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	B,P
Armando A. Pena	B,T
Peter R. Thomas	B,VP
Jeffrey D. Cross	S

AEP Credit, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO,P
Henry W. Fayne	D,VP
William J. Lhota	D
L. T. McDowell (11)	D
Armando A. Pena	D,T
Thomas V. Shockley, III	D
Susan Tomasky	D
Joseph H. Vipperman	D
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP C&I Company, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP,T
Geoffrey S. Chatas	VP
Mark W. Stewart	VP
Timothy A. King	S

AEP Delaware Investment Company

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,P,T
Mark A. Pyle (a)	D
Leonard V. Assante (a)	C

AEP Delaware Investment Company II

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,P,T
Mark A. Pyle (a)	D
Leonard V. Assante (a)	C

AEP Energy Management, L.L.C.

Name and Principal Address(a)	Position
Paul D. Addis	B
Henry W. Fayne	B
Susan Tomasky	B

AEP Energy Services Gas Holding Company

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Paul D. Addis (a)	P
Leonard V. Assante (a)	C

AEP Energy Services GmbH

Name and Principal Address(ee)	Position
Paul D. Addis (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T

AEP Energy Services Investments, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Paul D. Addis (a)	P
Leonard V. Assante (a)	C

AEP Energy Services Limited

Name and Principal Address(ff)	Position
Paul D. Addis (a)	D
Henry D. Jones	MD
Jeffrey D. Cross (a)	S
Armando A. Pena (a)	T

AEP Energy Services (Austria) GmbH

Name and Principal Address(gg)	Position
Paul D. Addis (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T

AEP Energy Services (Switzerland) GmbH

Name and Principal Address(hh)	Position
Paul D. Addis (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T
Georg Schlumpf (q)	MD

AEP Energy Services Ventures, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Paul D. Addis (a)	P
Leonard V. Assante (a)	C

AEP Energy Services Ventures II, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Paul D. Addis (a)	P
Leonard V. Assante (a)	C

AEP Energy Services Ventures III, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Leonard V. Assante (a)	C
Paul D. Addis (a)	P

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Energy Services, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D,P
Donald M. Clements, Jr.	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Eric J. van der Walde	D,SVP
Steven A. Appelt	SVP
Henry D. Jones (ff)	SVP
Andrew W. Patterson	SVP
Mark W. Stewart	SVP
David A. Banks	VP
Thomas A. Barry	VP
David B. Dunn	VP
Dwayne L. Hart	VP
Darren Lobdell	VP
Paul S. Mason	VP
P. M. O'Brien	VP
Douglas K. Penrod	VP
William C. Reed, II	VP
Glenn Riepl	VP
George Rooney	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Fiber Venture, LLC

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	B,P
Armando A. Pena	B,VP,T
Peter R. Thomas	B,VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S

AEP Funding Limited

Name and Principal Address(g)	Position
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D,T

AEP Gas Power GP, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Mark W. Stewart	VP
Timothy A. King	S

AEP Gas Power Systems, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B
Charles C. Cooper 430 Telser Road Lake Zurich, IL 60047-1588	B,P
Daniel O. Dickinson 430 Telser Road Lake Zurich, IL 60047-1588	B
John F. Norris, Jr.	B
Mark W. Stewart	B

AEP Generating Company

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CEO
Henry W. Fayne	D,VP
William J. Lhota	D,P
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
John F. Norris, Jr.	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Investments, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
Donald M. Clements, Jr.	D,P
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
William J. Lhota	D
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Ohio Commercial & Industrial Retail Company, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP,T
Geoffrey S. Chatas	VP
Mark W. Stewart	VP
Timothy A. King	S

AEP Ohio Retail Energy, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP,S
Armando A. Pena	B,T

AEP Power Marketing, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D,P
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Leonard V. Assante	C
John F. DiLorenzo, Jr.	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Pro Serv, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
John F. Norris, Jr.	D
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
John R. Jones	P
V. A. Lepore	SVP
Martin L. Mearhoff	VP
Ali Azad	VP
L. E. Dillahunty (ll)	VP
Mark A. Gray	VP
James A. Howard	VP
John A. Mazzone	VP
J. K. McWilliams	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Pushan Power, LDC

Name and Principal Address(g)	Position
Donald M. Clements, Jr. (a)	D,P
Jeffrey D. Cross (a)	D
Armando A. Pena (a)	D,VP,T
W.S. Walker & Co.	S

AEP Resource Services, LLC

Name and Principal Address(a)	Position
Frederick J. Boyle	B,VP,T
Donald M. Clements, Jr.	B,CB
Jeffrey D. Cross	VP,S

AEP Resources, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
Donald M. Clements, Jr.	D,P
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
William J. Lhota	D
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Donald E. Boyd	SVP
Frederick J. Boyle	VP
Thomas S. Jobes	VP
Dennis A. Lantzy	VP
James H. Sweeney Commerence Exec. Park III 1850 Centennial Park Dr.#480 Reston, VA 20191	VP
Christopher Wilson (k)	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

AEP Resources Australia Holdings Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
William J. Lhota (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources Australia Pty., Ltd.

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D,CB
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D
Mark A. Snape 100 Walker Street North Sydney 2060 Australia	D,S

AEP Resources do Brasil Ltda.

Name and Principal Address(cc)	Position
Hercules Celescuekci	DM

AEP Resources CitiPower I Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
William J. Lhota (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources CitiPower II Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
William J. Lhota (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources International, Limited

Name and Principal Address(g)	Position
Donald M. Clements, Jr. (a)	D,P
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D
Armando A. Pena (a)	D,VP,T,CFO
David Mustine (c)	SVP
Jeffrey D. Cross (a)	VP,GC
John R. Jones (a)	VP
Dennis A. Lantzy (a)	VP
Leonard V. Assante(a)	C,CAO
John F. DiLorenzo, Jr. (a)	S

AEP Resources Limited

Name and Principal Address(k)	Position
Donald M. Clements, Jr. (a)	D
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D,T
Chris Wilson	MD

AEP Resources Project Management Company, Ltd.

Name and Principal Address(g)	Position
Donald M. Clements, Jr. (a)	D,P
Jeffrey D. Cross (a)	D
Armando A. Pena (a)	D,T
W.S. Walker & Company	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Retail Energy, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,P
Henry W. Fayne	B,VP
Susan Tomasky	B,S
Armando A. Pena	T

AEP Texas Commercial & Industrial Retail GP, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Mark W. Stewart	VP
Timothy A. King	S

AEP Texas Retail GP, LLC

Name and Principal Address(a)	Position
Paul D. Addis	B,CB,P
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Mark W. Stewart	VP
Timothy A. King	S

AEP T&D Services, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Glenn M. Files (c)	B,VP
William J. Lhota	B,CB,P
David Mustine (c)	B,VP
Armando A. Pena	B,T
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	B,VP
Timothy A. King	S

AEP Wind GP, LLC

Name and Principal Address(a)	Position
Paul D. Addis	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Paul E. Graf (11)	VP
Dwayne L. Hart	VP
Armando A. Pena	VP,T
Timothy A. King	S

AEP Wind LP, LLC

Name and Principal Address(a)	Position
Paul D. Addis	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Paul E. Graf (11)	VP
Dwayne L. Hart	VP
Armando A. Pena	VP,T
Timothy A. King	S

AEPR Global Holland Holding B.V.

Name and Principal Address(g)	Position
AEP Resources, Inc. (a)	MD

AEPR Global Investments B.V.

Name and Principal Address(g)	Position
Donald M. Clements, Jr. (a)	MD
Jeffrey D. Cross (a)	MD
Ad C.G. de Beer	MD
Pieter Oosthoek	MD
Armando A. Pena (a)	MD

AEPR Global Ventures B.V.

Name and Principal Address(g)	Position
Donald M. Clements, Jr. (a)	MD
Jeffrey D. Cross (a)	MD
Ad C.G. de Beer	MD
Pieter Oosthoek	MD
Armando A. Pena (a)	MD

American Electric Power Service Corporation

Name and Principal Address(a)	Position
Paul D. Addis	D,EVP
Donald M. Clements, Jr.	D,EVP
E. Linn Draper, Jr.	D,CB,P,CEO
Henry W. Fayne	D,EVP
William J. Lhota	D,EVP
Thomas V. Shockley, III	D,VCB
Susan Tomasky	D,EVP,GC
Joseph H. Vipperman	D,EVP
Nicholas J. Ashooh	SVP
J. C. Baker	SVP
Jeffrey D. Cross	SVP
Thomas M. Hagan	SVP
Dale E. Heydlauff	SVP
Michael F. Moore	SVP,CIO
R. E. Munczinski	SVP
John F. Norris, Jr.	SVP
Armando A. Pena	SVP,T
Rodney B. Plimpton	SVP
Robert P. Powers	SVP
Melinda S. Ackerman	VP
Leonard V. Assante	VP,DC
Bruce M. Barber	VP
Edward J. Brady	VP
Bruce H. Braine	VP
Robert T. Burns (11)	VP
Geoffrey S. Chatas	VP
John F. DiLorenzo, Jr.	VP,S
W. N. D'Onofrio	VP
Joseph J. Hamrock 3455 Mill Run Dr. Hilliard, OH 43228	VP
Jane A. Harf	VP
Wendy G. Hargus (11)	VP
John D. Harper	VP
Anthony P. Kavanagh 801 Pennsylvania Ave. Washington, DC 20004	VP
Michael D. Martin	VP
Martin L. Mearhoff	VP

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

American Electric Power Service Corporation (Cont.)

Name and Principal Address(a)	Position
Mark W. Menezes 601 Pennsylvania Ave. Washington, DC 20004	VP
D. Michael Miller	VP
Richard A. Mueller	VP
Charles R. Patton 4000 W. 15th Street Austin, TX 78701	VP
Gary M. Prescott	VP
H. E. Rhodes (c)	VP
Daniel J. Rogier	VP
William L. Scott	VP
O. J. Sever	VP
William L. Sigmon, Jr.	VP
Waldo Zerger	VP

American Fiber Touch, LLC

Name and Principal Address(ii)	Position
Donald M. Clements, Jr. (a)	B
Perry J. Cole	B
Michael J. Meldahl	B
Peter R. Thomas (a)	B

Appalachian Power Company

Name and Principal Address(b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
R. D. Carson, Jr. 1051 East Cary Street, 7th Fl. Richmond, VA 23219	VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Stuart Solomon (t)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Ash Creek Mining Co.

Name and Principal Address(jj)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino, Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Australian Energy International Pty Ltd

Name and Principal Address(j)	Position
Alan John Bielby 147 Argyle Street Kowloon, Hong Kong	D
Donald E. Boyd (a)	D
Peter Albert Littlewood 22/F., CMG Asia Tower Gateway Harbour City, 15 Canton Road Kowloon, Hong Kong	D
Kenneth Warren Oberg 22/F., CMG Asia Tower Gateway Harbour City, 15 Canton Road Kowloon, Hong Kong	D
Paul Robert Rainey	D,S
Mark Snape 100 Walker Street North Sydney 2060 Australia	D

Australia's Energy Partnership

Name and Principal Address(j)	Position
Armando A. Pena (a)	T

Blackhawk Coal Company

Name and Principal Address(r)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

C3 Communications, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
Donald M. Clements, Jr.	D,P
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
William J. Lhota	D
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Peter R. Thomas	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Cardinal Operating Company

Name and Principal Address(l)	Position
Anthony J. Ahern 6677 Busch Blvd. Columbus, OH 43226	D
J. C. Baker (a)	D
Richard K. Byrne 6677 Busch Blvd. Columbus, OH 43226	D,VP
E. Linn Draper, Jr. (a)	D,P
John R. Jones (a)	D,VP
William J. Lhota (a)	D,VP
Ralph E. Luffler P.O. Box 250 Lancaster, OH 43130-0250	D,VP
Steven K. Nelson P.O. Box 280 Coshocton, OH 43812	D,VP
John F. Norris, Jr. (a)	D,VP
Michael L. Sims 3888 Stillwell Beckett Rd. Oxford, OH 45056	D
Leonard V. Assante (a)	C
Armando A. Pena (a)	T
John F. DiLorenzo, Jr. (a)	S

Cedar Coal Co.

Name and Principal Address(b)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley, III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino, Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Central and South West Corporation

Name and Principal Address(ll)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO,P
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D
Armando A. Pena (a)	D,T
Thomas V. Shockley,III (a)	D
Susan Tomasky (a)	D
Joseph H. Vipperman (a)	D
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Central Appalachian Coal Company

Name and Principal Address(b)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley, III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino, Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Central Coal Company

Name and Principal Address(b)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley, III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino, Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Central Ohio Coal Company

Name and Principal Address(m)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley, III (a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino, Jr. (e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr. (a)	S

Central Power and Light Company

Name and Principal Address(kk)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Alphonso R. Jackson 400 W. 15th Street, Ste 1500 Austin, TX 78701	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo,Jr. (a)	S

Chile Energy Holdings, L.L.C.

Name and Principal Address(p)	Position
Jeffrey D. Cross (a)	D,VP
Paul E. Graf (ll)	D,VP
Dwayne L. Hart (a)	D,P
Armando A. Pena (a)	D,VP
Susan Tomasky (a)	D
Geoffrey S. Chatas (a)	VP
Sandra S. Bennett (ll)	C
Wendy G. Hargus (ll)	T
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CitiPower Pty

Name and Principal Address(dd)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
Michael Codd, AC	D
Jeffrey D. Cross (a)	D,S
Brian Healey	D
William J. Lhota (a)	D
John Marshall	D
Armando A. Pena (a)	D,T
Simon Lucas	S

CitiPower Trust
Principal Address (j)

NONE

Colomet, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,P,CEO
Henry W. Fayne	D,VP
William J. Lhota	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

Columbus Southern Power Company

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
William J. Lhota	D,P,COO
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
Floyd W. Nickerson 88 East Broad Street, Ste 800 Columbus, OH 43215	VP
John F. Norris, Jr.	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

Conesville Coal Preparation Company

Name and Principal Address(a)	Position
Paul D. Addis	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley III	D,VP
Susan Tomasky	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

CSW Development-3, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Development-II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Development-I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW Eastex LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Energy Services, Inc.

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	D
Holly Keller Koeppel	D,P
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D
John F. DiLorenzo, Jr.	S

CSW Energy, Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D,P
Donald M. Clements, Jr.	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Paul E. Graf (11)	VP
Dwayne L. Hart	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

CSW Frontera GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Ft. Lupton, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW International Three, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Paul E. Graf (11)	VP
Leonard V. Assante	C

CSW International Two, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Paul E. Graf (11)	VP
Leonard V. Assante	C

CSW International (U.K.), Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Paul E. Graf (11)	VP
Leonard V. Assante	C

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW International, Inc. (a Delaware Corp.)

Name and Principal Address(a)	Position
Paul D. Addis	D,P
Donald M. Clements, Jr.	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Paul E. Graf (11)	VP
Dwayne L. Hart	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

CSW International, Inc. (a Cayman Corp.)

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Susan Tomasky	D
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Investments

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Donald M. Clements, Jr. (a)	D
E. Linn Draper, Jr. (a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley, III (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW Leasing, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB
Henry W. Fayne	D,P
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Nikita Zdanow 1211 Ave. Of the Americas New York, NY 10036	D
Kenneth Brown (11)	SVP
Jeffrey Knittle (11)	SVP
Jean Stein (11)	SVP
Joseph H. Vipperman	VP
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S
Armando A. Pena	T

CSW Mulberry II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Mulberry, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Nevada, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Northwest GP, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Northwest LP, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Orange II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW Orange, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Power Marketing, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Services International, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Sweeny GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Sweeny GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Sweeny LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Sweeny LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW UK Finance Company

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Donald M. Clements,Jr.(a)	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D,CB
M. J. Pavia	D,CFO
Armando A. Pena (a)	D,T
Thomas V. Shockley,III(a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW UK Holdings

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Donald M. Clements,Jr.(a)	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D,CB
M. J. Pavia	D,CFO
Armando A. Pena (a)	D,T
Thomas V. Shockley,III(a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW UK Investments Limited

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Donald M. Clements, Jr.(a)	D
E. Linn Draper, Jr. (a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley, III (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW Vale L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Susan Tomasky	D
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSWC Southwest Holdings, Inc.

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	D,P
Armando A. Pena	D,VP,T
Peter R. Thomas	D,VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Leonard V. Assante	C
Timothy A. King	S

CSWC TeleChoice Management, Inc.

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	D,P
Armando A. Pena	D,VP,T
Peter R. Thomas	D,VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Leonard V. Assante	C
Timothy A. King	S

CSWC TeleChoice, Inc.

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	D,P
Armando A. Pena	D,VP,T
Peter R. Thomas	D,VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Leonard V. Assante	C
Timothy A. King	S

CSWI Europe Limited

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Paul E. Graf (ll)	D
M. A. Nagle	S

CSWI Netherlands, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D,VP
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Leonard V. Assante	C

Datapult Limited Partnership

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Peter R. Thomas	VP
Timothy A. King	S

Datapult, LLC

Name and Principal Address(a)	Position
Donald M. Clements, Jr.	B,P
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Peter R. Thomas	B,VP
Timothy A. King	S

DECCO II, LLC

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Leonard V. Assante	C
Timothy A. King	S

Diversified Energy Contractors Company, LLC

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Leonard V. Assante	C
Timothy A. King	S

Energia de Mexicali, S de R.L.de C.V.

Name and Principal Address(pp)	Position
Donald M. Clements,Jr.(a)	B,P
Jeffrey D. Cross (a)	B
Armando A. Pena (a)	B
James H. Sweeney 1850 Centennial Park Drive Suite 480, Reston, VA 20191	B

Enershop Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D,CB,P
Steven A. Appelt	D,VP
Jeffrey D. Cross	D,VP
Armando A. Pena	D,VP,T
Geoffrey S. Chatas	VP
Mark W. Stewart	VP
Leonard V. Assante	C
Timothy A. King	S

Envirotherm, Inc.

Name and Principal Address(ll)	Position
Paul D. Addis (a)	D,CB,P
Steven A. Appelt (a)	D,VP
Jeffrey D. Cross (a)	D,VP
Armando A. Pena (a)	D,VP,T
Geoffrey S. Chatas (a)	VP
Mark W. Stewart (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Franklin Real Estate Company

Name and Principal Address(n)	Position
E. Linn Draper, Jr. (a)	D,P,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Frontera International Sales Limited

Name and Principal Address(nn)	Position
Mary Ellen M. Bourque	D
Jeffrey D. Cross (a)	D,VP
Paul E. Graf (ll)	D,VP
Dwayne L. Hart (a)	D,P
Armando A. Pena (a)	D,VP
Timothy A. King (a)	S
Wendy G. Hargus (ll)	T

Indiana-Kentucky Electric Corporation

Name and Principal Address(w)	Position
E. Linn Draper, Jr. (a)	D,P
Arthur R. Garfield 76 South Main Street Akron, OH 44308	D
J. Gordon Hurst 20 NW Fourth Street Evansville, IN 47741	D
Ronald G. Jochum 20 NW Fourth Street Evansville, IN 47741	D
John R. Sampson 101 W. Ohio Street, Ste 1320 Indianapolis, IN 46204	D
Peter J. Skrgic 800 Cabin Hill Drive Greensburg, PA 15601	D
William E. Walters 100 East Wayne Street South Bend, IN 46601	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Indiana Franklin Realty, Inc.

Name and Principal Address(d)	Position
E. Linn Draper, Jr. (a)	D,P,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Indiana Michigan Power Company

Name and Principal Address(d)	Position
Karl G. Boyd	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Jeffrey A. Drozda 101 W. Ohio, Suite 1320 Indianapolis, IN 46204	D
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Susanne M. Moorman	D
John R. Sampson 101 W. Ohio, Suite 1320 Indianapolis, IN 46204	D,VP
Thomas V. Shockley,III(a)	D,VP
Jackie S. Siefker 5000 Wheeling Ave. Muncie, IN 47304	D
D. B. Synowiec 2791 N. U.S. Highway 231 Rockport, IN 47635	D
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
William E. Walters 100 East Wayne Steet South Bend, IN 46601	D
A. Christopher Bakken III One Cook Place Bridgman, MI 49106	VP
Paul J. Brower 110 West Michigan,Ste 1000-A Lansing, MI 48933	VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
Armando A. Pena (a)	VP,T
Robert P. Powers (a)	VP
Michael W. Rencheck 500 Circle Drive Buchanan, MI 49107	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Industry and Energy Associates,L.L.C.

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Kenneth B. Rogers 9 Donald B. Dean Drive South Portland, ME 04106	VP
Leonard V. Assante	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Jefferson Island Storage & Hub L.L.C.

Name and Principal Address(bb)	Position
Paul D. Addis (a)	B,CB
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360	P
Geoffrey S. Chatas(a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Kentucky Power Company

Name and Principal Address(s)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
T. C. Mosher 101A Enterprise Drive Frankfort, KY 40602	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Kingsport Power Company

Name and Principal Address(b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
R. D. Carson, Jr. 1051 East Cary Street, 7th Fl. Richmond, VA 23219	VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Latin American Energy Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

LECTRIX International B.V.

Name and Principal Address(oo)	Position
Donald M. Clements, Jr.(a)	D
Hanfried Edward Fischer 01077 Neunkirchen am Brand Germany, Kapellenweg 9	D
Vincent Paul Unruh 59 Orinda View Road Orinda, CA 94563	D

LIG Chemical Company

Name and Principal Address(bb)	Position
Paul D. Addis (a)	B,CB
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG Liquids Company, L.L.C.

Name and Principal Address(bb)	Position
Paul D. Addis (a)	B,CB
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG Pipeline Company

Name and Principal Address(bb)	Position
Paul D. Addis (a)	D,CB
Jeffrey D. Cross (a)	D,VP
Armando A. Pena (a)	D,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG, Inc.

Name and Principal Address(bb)	Position
Paul D. Addis (a)	D,CB
Jeffrey D. Cross (a)	D,VP
Armando A. Pena (a)	D,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Louisiana Intrastate Gas Company, L.L.C.

Name and Principal Address(bb)	Position
Paul D. Addis (a)	B,CB
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Marregon Pty Limited

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
Jeffrey D. Cross (a)	D,S
William J. Lhota (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Simon Lucas (dd)	S

Marregon (No. 2) Pty Limited

Name and Principal Address(j)	Position
Donald E. Boyd (a)	D
Donald M. Clements, Jr.(a)	D
Jeffrey D. Cross (a)	D,S
William J. Lhota (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Simon Lucas (dd)	S

Mulberry Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (ll)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett (ll)	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

Mutual Energy L.L.C.

Name and Principal Address(a)	Position
Paul D. Addis	CB,P
Steven A. Appelt	VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S
Armando A. Pena	T

Mutual Energy Service Company, L.L.C.

Name and Principal Address(a)	Position
Paul D. Addis	CB,P
Steven A. Appelt	VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S
Armando A. Pena	T

Nanyang General Light Electric Co., Ltd.

Name and Principal Address(f)	Position
Donald E. Boyd (a)	D
Donald M. Clements,Jr.(a)	D,CB
Jeffrey D. Cross (a)	D,S
Bernard Hu 2648 Durfee Ave., #B El Monte, CA 91732	D
Dennis A. Lantzy (a)	D
Armando A. Pena (a)	D
Lu Ming Tao	D
Xu Xinglong	D,VCB
Hao Zhengshan	D

Newgulf Power Venture, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (ll)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

Noah I Power GP, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (ll)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

Ohio Power Company

Name and Principal Address(m)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
Floyd W. Nickerson 88 East Broad Street, Ste 800 Columbus, OH 43215	VP
John F. Norris, Jr.(a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Ohio Valley Electric Corporation

Name and Principal Address(w)	Position
Paul D. Addis (a)	D
H. Peter Burg 76 South Main Street Akron, OH 44308	D
E. Linn Draper, Jr. (a)	D,P
Henry W. Fayne (a)	D
Donald R. Feenstra 800 Cabin Hill Drive Greensburg, PA 15601	D
Arthur R. Garfield 76 South Main Street Akron, OH 44308	D
Chris Hermann 220 West Main Street Louisville, KY 40202	D
J. Gordon Hurst 20 NW Fourth Street Evansville, IN 47741	D
William J. Lhota (a)	D
Wayne T. Lucas 220 West Main Street Louisville, KY 40202	D
Alan J. Noia 10435 Downsville Pike Hagerstown, MD 21740	D
Guy L. Pipitone 76 South Main Street Akron, OH 44308	D
J. H. Randolph 139 East Fourth Street Cincinnati, OH 45202	D
H. Ted Santo 1065 Woodman Drive Dayton, OH 45432	D
Peter J. Skrgic 800 Cabin Hill Drive Greensburg, PA 15601	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Operaciones Azteca VIII, S. de R.L. de C.V.

Name and Principal Address(pp)	Position
Frederick J. Boyle (a)	D
Philip Cantner 5922 SW 34th Street Miami, FL 33155	D
Donald M. Clements,Jr.(a)	D
James H. Sweeney 1850 Centennial Park Drive Reston, VA 20191	D
J. Christopher Terajewicz 5 Magnolia Circle Norfolk, MA 02056	D
Robert H. Warburton 195 Dalton Road Holliston, MA 01746	D
Jorge Young Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D
Carlos de Maria y Campos Segura Torre Optima AV. Paseo de las Palmas #405, 3rd Fl.,Lomas de Chapultepec 11000 Mexico	S

Orange Cogen Funding Corp.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
Timothy A. King	S

Orange Cogeneration GP II, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,CEO
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
David L. Siddall 1001 Louisiana Street Houston, TX 77002	S

Orange Cogeneration GP, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,CEO
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
David L. Siddall 1001 Louisiana Street Houston, TX 77002	S

Orange Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Paul E. Graf (11)	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Sandra S. Bennett (11)	C
Timothy A. King	S
Wendy G. Hargus (11)	T

Pacific Hydro Limited

Name and Principal Address(aa)	Position
Donald E. Boyd (a)	D
Kingsley G. Culley	D,CB
Peter L. Downie	D
Michael C. Fitzpatrick	D
Jeffrey Harding	D
John L. C. McInnes	D
Mark A. Snape 100 Walker Street North Sydney 2060 Australia	D
Philip van der Riet	D
Peter F. Westaway	D
Matthew G. C. Williams	D
Anthony G. Evans	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Polk Power GP II, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,P
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,CEO
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
Timothy A. King	S

Polk Power GP, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,P
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,CEO
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
Timothy A. King	S

Price River Coal Company, Inc.

Name and Principal Address(d)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Public Service Company of Oklahoma

Name and Principal Address(qq)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
T. D. Churchwell 1601 N.W. Expressway,Ste 1400 Oklahoma City, OK 73118	VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo,Jr.(a)	S

SEEBOARD Group plc

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Donald M. Clements,Jr.(a)	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
J. Weight	D
Christopher Wilson (k)	D

SEEBOARD plc

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
T. J. Ellis	D
M. J. Pavia	D
J. Weight	D
M. A. Nagle	S

Servicios Azteca VIII,S.de R.L. de C.V.

Name and Principal Address(pp)	Position
Frederick J. Boyle (a)	D
Philip Cantner 5922 SW 34th Street Miami, FL 33155	D
Donald M. Clements,Jr.(a)	D
John H. Foster Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D,CB
Carlos Riva P.O. Box 137 Hamilton, MA 01936	D
James H. Sweeney 1850 Centennial Park Drive Reston, VA 20191	D
Enrique Tabora Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D
Carlos de Maria y Campos Segura Torre Optima AV. Paseo de las Palmas #405 3rd Fl., Lomas de Chapultepec 11000 Mexico	S

Shoreham Operations Company Limited

Name and Principal Address(mm)	Position
T. S. Clarke	D
Joseph H. Emberger (a)	D
E. S. Golland	D
Paul E. Graf (ll)	D
E. Kolodziej (ll)	D
Jeffrey D. Lafleur (ll)	D
C. D. MacKendrick	S

Simco Inc.

Name and Principal Address(a)	Position
Paul D. Addis	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante	DC
John F. DiLorenzo, Jr.	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

South Coast Power Limited

Name and Principal Address(mm)	Position
E. S. Golland	D
Paul E. Graf (ll)	D
Henry D. Jones (ff)	D
E. Kolodziej (ll)	D
B. J. McNaught	D

Southern Appalachian Coal Company

Name and Principal Address(b)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Southern Ohio Coal Company

Name and Principal Address(m)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Southwestern Electric Power Company

Name and Principal Address(rr)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Alphonso R. Jackson 400 W. 15th Street, Ste 1500 Austin, TX 78701	VP
Michelle S. Kalnas (c)	VP
Michael H. Madison	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo,Jr.(a)	S

Southwestern Electric Wholesale Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S

Tuscaloosa Pipeline Company

Name and Principal Address(bb)	Position
Paul D. Addis (a)	B,CB
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Michael K. Tate 8090 Highway 3128 Pineville, LA 71360-8991	P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Ventures Lease Co., LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Armando A. Pena	B,P,T
Geoffrey S. Chatas	VP
Timothy A. King	S

West Texas Utilities Company

Name and Principal Address(ss)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Alphonso R. Jackson 400 W. 15th Street, Ste 1500 Austin, TX 78701	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo,Jr.(a)	S

West Virginia Power Company

Name and Principal Address(t)	Position
E. Linn Draper, Jr. (a)	D,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
John F. Norris, Jr. (a)	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Wheeling Power Company

Name and Principal Address(u)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
William J. Lhota (a)	D,P,COO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
David H. Crabtree (c)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr.(a)	VP
M. P. Ryan (c)	VP
Stuart Solomon (t)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Windsor Coal Company

Name and Principal Address(m)	Position
Paul D. Addis (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Leonard V. Assante (a)	DC
John F. DiLorenzo, Jr.(a)	S

Yorkshire Cayman Holding Limited

Name and Principal Address(p)	Position
Stephen T. Haynes (a)	D
Richard C. Kelly (x)	D

Yorkshire Electricity Group plc

Name and Principal Address(o)	Position
Paul R. Bonavia (x)	D
Wayne H. Brunetti (x)	D,CB
Donald M. Clements,Jr.(a)	D
E. Linn Draper, Jr. (a)	D,VCB
Graham J. Hall	D,CEO
Richard C. Kelly (x)	D
Armando A. Pena (a)	D
Roger Dickinson	S

Yorkshire Holdings plc

Name and Principal Address(o)	Position
Paul R. Bonavia (x)	D
Wayne H. Brunetti (x)	D,VCB
Donald M. Clements,Jr.(a)	D
E. Linn Draper, Jr. (a)	D,CB
Richard C. Kelly (x)	D
Armando A. Pena (a)	D
Jeffrey D. Cross (a)	S

Yorkshire Power Finance 2 Limited

Name and Principal Address(p)	Position
Roger Dickinson (o)	D
Andrew G. Donnelly (o)	D
Graham J. Hall (o)	D
Linda Martin	S

Yorkshire Power Finance Limited

Name and Principal Address(p)	Position
Roger Dickinson (o)	D
Andrew G. Donnelly (o)	D
Graham J. Hall (o)	D
Linda Martin	S

Yorkshire Power Group Limited

Name and Principal Address(o)	Position
Paul R. Bonavia (x)	D
Wayne H. Brunetti (x)	D,VCB
Donald M. Clements,Jr.(a)	D
E. Linn Draper,Jr. (a)	D,CB
Richard C. Kelly (x)	D
Armando A. Pena (a)	D,CFO
Jeffrey D. Cross (a)	S

YPG Holdings LLC

Name and Principal Address(a)	Position
Armando A. Pena	CB
Richard C. Kelly (x)	P
Jeffrey D. Cross	VP,S
Brian P. Jackson (x)	VP,T

ITEM 6. (CONTINUED)

Part II. Each officer and director with a financial connection within the provisions of Section 17(c) of the Act are as follows:

Name of Officer or Director (1)	Name and Location of Financial Institution (2)	Position Held in Financial Institution (3)	Applicable Exemption Rule (4)
David W. Dupert	Merchants Bank of N.Y. Holding Corp. N.Y., N.Y.	Director	70(d)
	Provident Bank of Maryland Investment Co. Baltimore, MD	Director	70(d)
	State Bank of Long Island Financial Services Corp. Long Island, N.Y.	Director	70(d)
	State Bank of Long Island Portfolio Management Corp. Long Island, N.Y.	Director	70(d)
	Central Pennsylvania Investment Company Parent Co: Omega Financial Corp. State College, PA	Director	70(d)
William R. Howell	Bankers Trust Bank New York, N.Y.	Director	70(b)
	Bankers Trust Corp. New York, N.Y.	Director	70(b)
L.A. Hudson, Jr.	American National Bankshares, Inc. Danville, Virginia	Director	70(a)
	American National Bank & Trust Co. Danville, Virginia	Director	70(a)
Alphonso R. Jackson	J.P. Morgan Chase Bank of Texas Houston, Texas	Advisory Director	70(f)
W.J. Lhota	Huntington Bancshares, Inc. Columbus, Ohio	Director	70(c), (f)
James L. Powell	First National Bank of Mertzon Mertzon, Texas	Advisory Director	70(a)
J.H. Randolph	PNC Financial Group Pittsburgh, PA	Director	70(d)
M.P. Ryan	Firstar Columbus, Ohio	Advisory Director	70(f)
Richard L. Sandor	Bear, Stearns Financial Products, Inc. Chicago, Illinois	Director	70(b)
	Bear, Stearns Trading Risk Management Inc. Chicago, Illinois	Director	70(b)
Georg Schlumpf	Credit Suisse Zurich, Switzerland	Managing Officer	70(d)
Donald G. Smith	First Union National Bank - Mid Atlantic of Virginia Roanoke, Virginia	Director	70(a)
Lu Ming Tao	City Commerical Bank of Nanyang Nanyang City Province, China	Vice Chairman	70(c)

ITEM 6. (continued)

Part III. The disclosures made in the System companies' most recent proxy statement and annual report on Form 10-K with respect to items (a) through (f) follow:

(a) COMPENSATION OF DIRECTORS AND EXECUTIVE OFFICERS

Executive Compensation

The following table shows for 2000, 1999 and 1998 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 AEP at December 31, 2000.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation Payouts	
Name	Year	Salary ($)	Bonus ($)(1)	LTIP Payouts($)(1)	All Other Compensation ($)(2)
E. Linn Draper, Jr.	2000	850,000	485,775	-0-	106,699
	1999	820,000	208,280	-0-	103,218
	1998	780,000	194,376	345,906	104,941
Paul D. Addis	2000	500,000	6,500,000	-0-	44,547
William J. Lhota	2000	415,000	173,927	-0-	62,394
	1999	400,000	71,120	-0-	55,690
	1998	380,000	82,859	134,266	56,493
Donald M. Clements, Jr.	2000	390,000	163,449	-0-	45,979
	1999	375,000	66,675	-0-	38,484
	1998	350,000	76,317	60,047	39,040
Henry W. Fayne	2000	365,000	152,972	-0-	47,074
	1999	315,000	56,007	-0-	34,885
	1998	290,000	63,234	61,555	34,124

Notes to Summary Compensation Table

(1) Amounts in the "Bonus" column reflect awards under the Senior Officer Annual Incentive Compensation Plan and, in the case of Mr. Addis, the AEP Energy Services Incentive Compensation Plan. Payments are made in the first quarter of the succeeding fiscal year for performance in the year indicated.

Amounts in the "Long-Term Compensation" – Payouts column reflect performance share unit targets earned under the AEP 2000 Long-Term Incentive Plan (and predecessor Performance Share Incentive Plan) for three-year performance periods.

(2) Amounts in the "All Other Compensation" column include (i) AEP's matching contributions under the AEP Retirement Savings Plan and the AEP Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan, (ii) subsidiary companies director fees, (iii) vehicle allowance, and (iv) split -dollar insurance. In August 2000, AEP discontinued providing vehicles for its executive officers and began paying them a monthly allowance. Split-dollar insurance represents the present value of the interest projected to accrue for the employee's benefit on the current year's insurance premium paid by AEP. Cumulative net life insurance premiums paid are recovered by AEP at the later of retirement or 15 years. Detail of the 2000 amounts in the "All Other Compensation" column is shown below.

Item	Dr. Draper	Mr. Addis	Mr. Lhota	Mr. Clements	Mr. Fayne
Savings Plan Matching Contributions	$ 3,187	$ 3,687	$ 5,100	$ 3,544	$ 5,100
Supplemental Savings Plan Matching Contributions	22,313	11,313	7,350	8,156	5,850
Subsidiaries Directors Fee	13,060	3,805	11,405	3,900	13,060
Vehicle Allowance	6,000	4,000	8,143	4,983	5,000
Split-Dollar Insurance	62,139	21,742	30,396	25,396	18,064
Total All Other Compensation	$106,699	$44,547	$62,394	$45,979	$47,074

(3) No 1999 and 1998 compensation information is reported for Mr. Addis because he was not an executive officer in these years.

Compensation of Directors

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. The other members of the Board receive an annual retainer of $25,000 for their services, an additional annual retainer of $3,500 for each Committee that they chair, a fee of $1,200 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 $1,200 per day for any inspection trip or conference.

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 shares of AEP Common Stock and/or units that are equivalent in value to shares of Common Stock ("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 Common Stock is 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 Common Stock 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 Common Stock, or a combination of both, as elected by the director.

Stock Unit Accumulation Plan. The Stock Unit Accumulation Plan for Non-Employee Directors annually awards 750 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. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. 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. The current policy, effective September 1, 2000 through September 1, 2001, has a premium of $11,500 and AEP expects to renew this 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 ($440 for 2000).

(b) OWNERSHIP OF SECURITIES

The following table sets forth the beneficial ownership of AEP Common Stock and stock-based units as of January 1, 2001 for all directors as of the date of this proxy statement, all nominees to the 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 shares of Common Stock 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	SHARES	STOCK UNITS(a)	TOTAL
P.D. Addis	10,032 (b) (c) (d)	22,572	32,604
E.R. Brooks	151,895 (b) (e)	785	152,680
D. M. Carlton	6,431	785	7,216
D. M. Clements, Jr.	2,354 (b)	16,497	18,851
J. P. DesBarres	5,000 (c)	1,854	6,854
E. L. Draper, Jr.	9,535 (b) (c)	106,181	115,716
H. W. Fayne	5,590 (b) (f)	11,163	16,753
R. W. Fri	2,000	2,560	4,560
W. R. Howell	1,692	785	2,477
L. A. Hudson, Jr.	1,853 (d)	4,566	6,419
L. J. Kujawa	1,326 (d)	4,305	5,631
W. J. Lhota	18,854 (b) (c) (f)	16,249	35,103
J. L. Powell	4,020	785	4,805
R. L. Sandor	1,092	785	1,877
T. V. Shockley, III	93,965 (b) (d) (e)	-0-	93,965
D. G. Smith	2,500	2,967	5,467
L. G. Stuntz	1,500 (c)	4,618	6,118
K. D. Sullivan	-0-	3,477	3,477
M. Tanenbaum	1,720	4,517	6,237
All directors, nominees and executive officers as a group (21 persons)	420,794 (f) (g)	210,322	631,116

Notes on Stock Ownership

(a) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.

(b) Includes the following numbers of share equivalents held in the AEP Retirement Savings Plan and, for Messrs. Brooks and Shockley, the CSW Retirement Savings Plan (in the case of the AEP Retirement Savings Plan such persons have sole voting power, but the investment/disposition power is subject to the terms of the Savings Plan): Mr. Addis, 377; Mr. Brooks, 41,833; Mr. Clements, 2,354; Dr. Draper, 3,947; Mr. Fayne, 5,041: Mr. Lhota, 16,674; Mr. Shockley, 6,234; and all executives officers, 89,803.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Mr. Addis, 5,623; Mr. DesBarres, 5,000; Dr. Draper, 5,588; Mr. Lhota, 2,180; and Ms. Stuntz, 300

(d) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Mr. Addis, 4;032; Dr. Hudson, 750; Mr. Kujawa, 26; and Mr. Shockley, 496.

(e) Includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Brooks, 65,105 and Mr. Shockley, 49,938.

(f) Does not include, for Messrs. Fayne and Lhota, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne and Lhota 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.

(g) Represents less than 1% of the total number of shares outstanding.

(c) CONTRACTS AND TRANSACTIONS WITH SYSTEM COMPANIES

None

(d) INDEBTEDNESS TO SYSTEM COMPANIES

None

(e) PARTICIPATION IN BONUS AND PROFIT SHARING ARRANGEMENTS AND OTHER BENEFITS

Long-Term Incentive Plans _ Awards In 2000

Each of the awards set forth below establishes performance share unit targets, which represent units equivalent to shares of Common Stock, pursuant to the Company's 2000 Long-Term Incentive Plan. Since it is not possible to predict future dividends and the price of AEP Common Stock, 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 shares of Common Stock 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. 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 20%, 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 phantom stock units (equivalent to shares of AEP Common Stock) 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 Common Stock.

Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Estimated Future Performance Share Non-Stock Price- Threshold (#)	Target (#)	Maximum (#)
E. L. Draper, Jr.	19,988	2000-2002	3,998	19,988	39,976
P.D. Addis	3,135	2000-2002	627	3,135	6,270
W. J. Lhota	7,157	2000-2002	1,431	7,157	14,314
D. M. Clements, Jr.	6,725	2000-2002	1,345	6,725	13,450
H. W. Fayne	6,294	2000-2002	1,259	6,294	12,588

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 or by the Central and South West Corporation Cash Balance Retirement Plan), including the executive officers of AEP. The Retirement Plan is a noncontributory defined benefit plan.

The Retirement Plan was amended effective January 1, 2001. The amendment provides that the final average pay benefit accrual formula currently in effect terminates on December 31, 2010 and, effective January 1, 2001, a cash balance accrual formula is added to the Retirement Plan. Employees participating in the Retirement Plan on December 31, 2000 accrue retirement benefits under both formulas and employees hired after December 31, 2000 accrue retirement benefits solely under the cash balance formula. Employees accruing benefits under both formulas may choose either the final average pay formula or the cash balance formula for their accrued benefit at the time employment is terminated. The accrued benefit earned by an employee under the final average pay formula as of December 31, 2010, the date the final average pay formula will be discontinued, is the minimum benefit an employee can receive from the Retirement Plan after that time.

The following table shows the approximate annual annuities that would be payable to employees in certain higher salary classifications under the final average pay formula, assuming retirement at age 65 after various periods of service.

Pension Plan Table

Highest Average Annual Earnings	Years of Accredited Service 15	20	25	30	35	40
$ 400,000	$ 93,345	$ 124,460	$155,575	$186,690	$217,805	$244,465
500,000	117,345	156,460	195,575	234,690	273,805	307,130
600,000	141,345	188,460	235,575	282,690	329,805	369,795
700,000	165,345	220,460	275,575	330,690	385,805	432,460
900,000	213,345	284,460	355,575	426,690	497,805	557,790
1,200,000	285,345	380,460	475,575	570,690	665,805	745,785
1,700,000	405,345	540,460	675,575	810,690	945,805	1,059,110

The amounts shown in the table are the straight life annuities payable under the Retirement Plan final average pay formula 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 55 and 62. If an employee retires after age 62, there is no reduction in the retirement annuity.

Compensation upon which retirement benefits under the final average pay formula are based, for the executive officers named in the Summary Compensation Table above (except for Mr. Addis), consists of the average of the 36 consecutive months of the officer's highest aggregate salary and Senior Officer Annual 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. In the case of Mr. Addis, compensation upon which his retirement benefits are based consists of salary and annual AEP Energy Services Incentive Compensation Plan awards up to a maximum of 30% of salary.

Under the cash balance formula each employee has an account to which dollar amount credits are allocated annually based on a percentage of the employee's compensation. Compensation for the cash balance formula includes annual salary and annual incentive compensation plan awards up to a maximum total compensation of $1,000,000. The applicable percentage is determined by age and years of service with AEP as of December 31 of each year (or as of the employee's termination date, if earlier). The following table shows the percentage used to determine dollar amount credits at the age and years of service indicated:

Sum of Age Plus Years of Service	Applicable Percentage
<30	3.0%
30-49	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

To transition from the final average pay formula to the cash balance formula, the employee's account under the cash balance formula was credited with an opening balance using a number of factors.

The estimated annual annuities at age 65 under the cash balance formula payable to the executive officers named in the Summary Compensation Table are:

Name	Annual Benefit
E.L. Draper, Jr.	$945,000
P.D. Addis	438,000
W.J. Lhota	469,000
D.M. Clements, Jr.	351,000
H.W. Fayne	329,000

These amounts are based on the following assumptions:

- Salary amounts shown in the Salary column for calendar year 2000 are used with no subsequent adjustments in future years plus annual incentive awards at the 2000 target level.
- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 5.78% and the 1983 Group Annuity Mortality Table.

AEP maintains a supplemental retirement plan which provides for the payment of:

- Retirement benefits that are not payable due to limitations imposed by Federal tax law on benefits paid by qualified plans.
- Supplemental retirement benefits provided by individual agreements with certain AEP employees.

The supplemental retirement plan was amended to provide for supplemental benefits under both the final average pay formula and the cash balance formula. Retirement Plan benefits shown above include all supplemental retirement benefits.

Dr. Draper and Messrs. Addis and Clements have individual agreements with AEP which provide them with supplemental retirement benefits that credit them with years of service in addition to their years of service with AEP as follows: Dr. Draper, 24 years; Mr. Clements, 15 years; and Mr. Addis, 18.5 years. The agreements each provide that these supplemental retirement benefits are reduced by their actual pension entitlements from plans sponsored by prior employers.

As of December 31, 2000, for the executive officers named in the Summary Compensation Table, the number of years of service applicable for retirement benefit calculation purposes under either the final average pay formula or the cash balance formula were as follows: Dr. Draper, 32 years; Mr. Addis, 21.5 years; Mr. Lhota, 35 years; Mr. Clements, 21 years; and Mr. Fayne, 25 years. The years of service for Dr. Draper and Messrs. Addis and Clements include years of service provided by their respective agreements with AEP described in the preceding paragraph.

Six AEP System employees (including Messrs. Lhota and Fayne) 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 2001 of the executive officers named in the Summary Compensation Table, none of them would receive any supplemental benefits.

AEP made available a voluntary deferred-compensation program in 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% annually 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 retirement at age 65, annual supplemental retirement payments under the 1986 program.

	1986 Program	
Name	Annual Amount Deferred (4-Year Period)	Annual Amount of Supplemental Retirement Payment (15-Year Period)
H. W. Fayne	$9,000	$95,400

Severance Plan

In connection with the merger with Central and South West Corporation, AEP's Board of Directors adopted a severance plan on February 24, 1999, effective March 1, 1999, that includes Messrs. Addis, Lhota, Clements, and Fayne. The severance plan provides for payments and other benefits if, at any time before June 15, 2002 (the second anniversary of the merger consummation date), the officer's employment is terminated (i) by AEP without "cause" or (ii) by the officer because of a detrimental change in responsibilities or a reduction in salary or benefits. Under the severance plan, the officer will receive:

- A lump sum payment equal to three times the officer's annual base salary plus target annual incentive under the Senior Officer Annual Incentive Compensation Plan.

- Maintenance for a period of three additional years of all medical and dental insurance benefits substantially similar to those benefits to which the officer was entitled immediately prior to termination, reduced to the extent comparable benefits are otherwise received.

- Outplacement services not to exceed a cost of $30,000 or use of an office and secretarial services for up to one year.

AEP's obligation for the payments and benefits under the severance plan is subject to the waiver by the officer of any other severance benefits that may be provided by AEP. In addition, the officer agrees to refrain from the disclosure of confidential information relating to AEP.

Change-In-Control Agreements

AEP has change-in-control agreements with Dr. Draper and Messrs. Addis, Lhota, Clements, and Fayne. If there is a "change-in-control" of AEP and the employee's employment is terminated by AEP or by the employee for reasons substantially similar to those in the severance plan, these agreements provide for substantially the same payments and benefits as the severance plan with the following additions:

- Three years of service credited for purposes of determining non-qualified retirement benefits.

- Transfer to the employee of title to AEP's automobile then assigned to the employee.

- Payment, if required, to make the employee whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.

"Change-in-control" means:

- The acquisition by any person of the beneficial ownership of securities representing 25% or more of AEP's voting stock.

- A change in the composition of a majority of the Board of Directors under certain circumstances within any two-year period.

- Approval by the shareholders of the liquidation of AEP, disposition of all or substantially all of the assets of AEP or, under certain circumstances, a merger of AEP with another corporation.

(f) RIGHTS TO INDEMNITY

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, Energy Insurance Mutual, Clarendon National Insurance Company, CNA, Great American Insurance Company, Royal-Sun Alliance, Zurich American Insurance company, Zurich UK, and The Federal Insurance Company, effective January 1, 2001 through December 31, 2001, and pays up to an aggregate amount of $275,000,000 on any one claim and in any one policy year. The total annual cost for the seven policies is $1,244,066.

Fiduciary liability insurance provides coverage for AEP 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. This coverage, provided by Associated Electric & Gas Insurance Services, The Federal Insurance Company, and Zurich American Insurance Company was renewed, effective July 1, 2000 through June 30, 2003, for a cost of $355,350. It provides $100,000,000 of aggregate coverage with a $500,000 deductible for each loss.

ITEM 7. CONTRIBUTIONS AND PUBLIC RELATIONS

Expenditures, disbursements or payments during the year, in money, goods or services directly or indirectly to or for the account of:

(1) Any political party, candidate for public office or holder of such office, or any committee or agent thereof.
- NONE

(2) Any citizens group or public relations counsel.

Calendar Year 2000

Name of Company and Name or Number of Recipients or Beneficiaries	Purpose	Accounts Charged, if any, Per Books of Disbursing Company	Amounts (in thousands)
NONE			

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies are as follows:

Calendar Year 2000

Nature of Transactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4) (in thousands)	Date of Contract (5)	In Effect On Dec. 31st (Yes or No) (6)
Machine Shop Services	APCo	System Operating Companies	$ 9,366	1/01/79	Yes
Racine Hydro Service	APCo	OPCo	80	6/01/78	Yes
Simulator Training Services	APCo	System Operating Companies	920	12/12/87	Yes
Communications Services	AEPCLLC	APCo	2,582	3/04/98	Yes
Communications Services	AEPCLLC	KPCo	114	11/18/97	Yes
Communications Services	AEPCLLC	I&M	733	10/24/98	Yes
Communications Services	AEPCLLC	OPCo	1,509	2/12/98	Yes
Communications Services	AEPCLLC	CSPCo	758	2/12/98	Yes
Project & Administrative Svc.	KGPCo	AEPCLLC	(138)	6/01/99	Yes
Project & Administrative Svc.	APCo	AEPCLLC	(2,520)	3/04/98	Yes
Project & Administrative Svc.	KPCo	AEPCLLC	(120)	11/18/97	Yes
Project & Administrative Svc.	I&M	AEPCLLC	(1,174)	10/24/98	Yes
Project & Administrative Svc.	OPCo	AEPCLLC	(329)	2/12/98	Yes
Barging Transportation	I&M	System Operating Companies	24,797	5/01/86	Yes
A/R Factoring	AEP CREDIT	CPL	15,712	6/16/00	Yes
A/R Factoring	AEP CREDIT	CSPCo	10,754	6/16/00	Yes
A/R Factoring	AEP CREDIT	I&M	6,819	6/16/00	Yes
A/R Factoring	AEP CREDIT	KPCo	1,870	6/16/00	Yes
A/R Factoring	AEP CREDIT	OPCo	8,357	6/16/00	Yes
A/R Factoring	AEP CREDIT	PSO	8,258	6/16/00	Yes
A/R Factoring	AEP CREDIT	SWEPCo	9,183	6/16/00	Yes
A/R Factoring	AEP CREDIT	WTU	4,039	6/16/00	Yes
Coal Mine Shutdown Costs	BHCCo	I&M	182	1/01/82	Yes
Coal Mine Shutdown Costs	CeCCo	APCo	3,260	12/01/76	Yes
Coal Mine Shutdown Costs	CACCo	APCo	(199)	9/14/83	Yes
Coal	CCPC	CSPCo	12,111	11/05/84	Yes
Coal	COCCo	OPCo	42,711	4/01/83	Yes
Coal Mine Shutdown Costs	SACCo	APCo	(182)	3/01/78	Yes
Coal	SOCCo	OPCo	471,030	2/01/74	Yes
Coal Mine Shutdown Costs	SOCCo	OPCo	20,211	10/01/72	Yes
Coal	WCCo	OPCo	45,169	1/01/83	Yes
Operating Services	AEPRGHC	AEPES	25,192	5/17/99	Yes

Transactions between AEP System companies pursuant to the Affiliated Transactions Agreement dated December 31, 1996 are reported in Exhibit F of this U5S.

ITEM 8. (CONTINUED)

Part II. Contracts to purchase services or goods between any System company and (1) any affiliate company (other than a System company) or (2) any other company in which any officer or director of the System company, receiving service under the contract, is a partner or owns 5 percent or more of any class of equity securities. - NONE.

Part III. Employment of any other person, by any System company, for the performance on a continuing basis, of management, supervisory or financial advisory services. - NONE.

ITEM 9. WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES

Part I.

The following table shows the required information for investment in wholesale generation and foreign utility companies as of December 31, 2000:

(a) Company name, business address, facilities and interest held;
(b) Capital invested, recourse debt, guarantees and transfer of assets between affiliates;
(c) Debt to equity ratio and earnings;
(d) Contracts for service, sales or construction with affiliates.

Foreign Utility Companies:

(a) SEEBOARD plc
Forest Gate, Brighton Road
Crawley, West Sussex RH11 9BH
United Kingdom
Distrubites and supplies electricity to approximately 2 million customers in the United Kingdom.
AEP owns 100%.
(b) Capital invested - $829 million. Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE.
(c) Debt is equity ratio - 1 to 1; Earnings $99 million.
(d) NONE

(a) Yorkshire Electricity Group plc
Wetherby Road,
Scarcroft, Leeds LS14 3HS
Great Britain
Distributes and supplies electricity to approximately 2 million customers in the United Kingdom.
AEP owns 50%.
(b) Capital invested $362 million, Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE.
(c) Debt to equity ratio 2.2 to 1; Earnings - $88 million
(d) NONE

ITEM 9. (CONTINUED)
PART I. (CONTINUED)

(a) Nanyang General Light Electric Co., Ltd.
Dayuan Zhuan Village
Pushan Town, Nanyang City
People's Republic of China

Owns and operates a two unit electric generating plant in China.
AEP owns 70%.

(b) Capital invested $97 million. Recourse debt - NONE.
Guarantees - NONE.
Asset transfers - NONE.

(c) Debt to equity ratio - 1.6 to 1.
Earnings - $11 million.

(d) Nanyang has contracts with AEP Resource Service Company for consulting and administrative service which resulted in a fee of $800,000.

(a) Empresa de Eletricidade Vale Paranapanema S.A.
Avenida Paulista, No. 2439, 5th floor
Sao Paulo, Sao Paulo
Brazil
Owns a majority interest in five electric operating companies in Brazil.
AEP owns 22%.

(b) Capital invested $149 million.
Recourse debt - NONE.
Convertible debt - $60 million.
Guarantees - NONE.
Asset transfers - NONE.

(c) Debt to equity ratio 0.2 to 1. Earnings $2.7 million.

(d) NONE

(a) Pacific Hydro Limited
Level 8
474 Flinders Street
Melbourne, Victoria
3000 Australia

Develops and owns hydroelectric facilities in the Asia Pacific region.
AEP owns 20%.

(b) Capital invested - $17 million.
Recourse Debt - NONE.
Guarantees - NONE.
Assets transferred - NONE.

(c) Noncurrent liabilities to equity ratio - 2 to 1.
Earnings - $10 million.

(d) NONE

(a) Enertek, S.A. de C.V.
Ave. Gomez Morin No. 350 Int
607 Col. Valle del Campestre
C.P. 66265
San Pedro Garza Garcia N.
Owns and operates a gas-fired cogeneration facility in Mexico.
AEP owns 100%.

(b) Capital invested - $4 million.
Construction loans - $26 million.
Recourse debt - NONE
Guarantees - NONE
Asset Transfers - NONE.

(c) Debt to equity ratio - 3.3 to 1. Earnings - Not Available.
(d) NONE

(a) CitiPower Pty.
600 Bourke Street
Melbourne Victoria
3000 Australia
CitiPower distributes and sells electricity to approximately 260,000 customers over 3,990 miles of distribution lines.
AEP owns 100%.
(b) Capital invested - $343 million.
Recourse debt - NONE.
Guarantees - NONE.
Asset transfers - NONE.
(c) Debt to equity ratio - 5.4 to 1.
Earnings - $17 million.
(d) NONE.

(a) AEP Energy Services Limited
29/30 St. James's Street
London SW1A 1HB
Great Britain
AEP owns 100%.
(b) Capital invested - $5 million.
Recourse debt - NONE.
Guarantees - NONE.
(c) Earnings - $13 million.
(d) Not Available.

(a) InterGen Denmark, Aps
Torre Chapultepec,
Piso 13,
Ruben Dario 281, Col.
Bosques de
Chapultepec, Mexico, D.F. 11520.
Construction and operation of a 600 megawatt natural gas-fired, combined cycle plant.
AEP owns 50%.

(b) Capital invested - $50 million. Loans for affiliates - $7 million. Guarantees - NONE.
Asset transfers - NONE.

(c) Earnings - ($307,000).

(d)

Nature of Transactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Fees or Revenues (4) (in thousands)	Date of Contract (5)	In Effect On Dec. 31st (Yes or No) (6)
Consulting Services	RESCo	NGLE	$ 333	4/01/97	No
Administrative Services	RESCo	NGLE	458	11/04/99	Yes
Consulting Services	AEPR	CTP	1,958	12/31/98	Yes

Exempt Wholesale Generators:

(a) CSW Development-3, Inc.
1616 Woodall Rodgers Freeway
Dallas, Texas 75202

Inactive - no capital invested

(a) CSW Northwest GP, Inc.
1616 Woodall Rodgers Freeway
Dallas, Texas 75202

Inactive - no capital invested

ITEM 9. (CONTINUED)
PART I. (CONTINUED)

(a) CSW Northwest LP, Inc.
1616 Woodall Rodgers Freeway
Dallas, Texas 75202

Inactive - no capital invested

(a) Frontera Generation Limited Partnership
1616 Woodall Rodgers Freeway
Dallas, Texas 75202
Owns and operates a 500 megawatt plant in Texas.
AEP owns 100%.
(b) Capital invested - $184 million
(a) Newgulf Power Venture, Inc.
1616 Woodall Rodgers Freeway
Dallas, Texas 75202
Operation of an 85 megawatt plant in Texas.
AEP owns 100%.
(b) Capital invested - $17 million

Part II.

See Exhibit's H and I

Part III.

American Electric Power Company, Inc.'s aggregate investment in foreign utility companies is $1.6 billion and in exempt wholesale generators is $201 million which is 25.6% of its investment in domestic public utility subsidiary companies.

ITEM 10. FINANCIAL STATEMENTS AND EXHIBITS

FINANCIAL STATEMENTS	Section and Page No.
Consent of Independent Public Accountants	A-1
Consolidating Statements of Income	B-1 to B-13
Consolidating Balance Sheets	B-14 to B-33
Consolidating Statements of Cash Flows	B-34 to B-43
Consolidating Statements of Retained Earnings	B-44 to B-46
Note to Consolidating Financial Statements	C
Financial Statements of Subsidiaries Not Consolidated:	
OVEC	D-1 to D-4

EXHIBITS

Exhibit A	E
Exhibit B & C	**
Exhibit D	**
Exhibit E	**
Exhibit F	**
Exhibit G (Not Applicable)	
Exhibit H	**
Exhibit I	***

** These Exhibits are included only the in copy filed with the Securities and Exchange Commission.
*** Filed confidentially pursuant to Rule 104(b) of the PUHCA.

SIGNATURE

The undersigned system company has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, pursuant to the requirements of the Public Utility Holding Company Act of 1935.

AMERICAN ELECTRIC POWER COMPANY, INC.

By /s/ Armando A. Pena
Armando A. Pena
Treasurer

April 27, 2001

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in this American Electric Power Company, Inc. Annual Report (Form U5S) to the Securities and Exchange Commission, filed pursuant to the Public Utility Holding Company Act of 1935, for the year ended December 31, 2000, of our reports dated February 26, 2001, included in or incorporated by reference in the combined Annual Report (Form 10-K) to the Securities and Exchange Commission of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries for the year ended December 31, 2000.

Deloitte & Touche LLP
Columbus, Ohio

April 27, 2001

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	13,701,548,455.63	(2,401,388,260.31)	0.00	1,860,164,785.95
PROVISION FOR RATE REFUND	(6,769,380.00)	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	13,694,779,075.63	(2,401,388,260.31)	0.00	1,860,164,785.95
OPERATING EXPENSES				
OPERATIONS				
FUEL	3,368,248,982.70	(681,844.01)	986.64	369,161,392.34
PURCHASED POWER	2,318,012,546.90	(1,677,231,519.89)	0.00	477,909,526.19
OTHER OPERATION	3,182,637,764.45	(733,280,680.00)	99,696,705.32	282,609,354.01
MAINTENANCE	831,090,277.76	(44,414,701.78)	73,872.53	124,492,931.79
TOTAL OPER/MAINT EXPENSES	9,704,091,571.81	(2,451,506,745.68)	99,771,564.49	1,254,173,204.33
DEPRECIATION AND AMORTIZATION	1,249,500,590.03	(4,116,456.83)	0.00	163,089,226.34
TAXES OTHER THAN INCOME TAXES	684,140,369.69	(23,235,973.84)	0.00	111,691,856.47
STATE, LOCAL & FOREIGN INCOME TAXES	41,771,677.53	(344,779.30)	0.00	14,755,373.00
FEDERAL INCOME TAXES	546,888,051.19	1,025,616.00	(21,723,925.00)	115,301,300.00
TOTAL OPERATING EXPENSES	12,222,290,260.25	(2,482,280,339.65)	78,047,639.49	1,659,010,960.14
NET OPERATING INCOME	1,472,488,815.38	80,892,079.34	(78,047,639.49)	201,153,825.81
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	109,981,970.21	(5,265,699,056.17)	458,701,861.33	1,484,852,405.75
OTHER INCOME DEDUCTIONS	(101,957,504.77)	4,721,260,925.80	(86,921.28)	(1,470,851,427.97)
TAXES APPL TO OTHER INC &DED	(19,871,865.36)	(11,166.00)	(284,948.66)	(3,394,204.46)
NET OTHR INCOME AND DEDUCTIONS	(11,847,399.92)	(544,449,296.37)	458,329,991.39	10,606,773.32
INCOME BEFORE INTEREST CHARGES	1,460,641,415.46	(463,557,217.03)	380,282,351.90	211,760,599.13
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	768,385,165.41	(3,538,087.04)	607,475.44	115,562,008.73
INT SHORT TERM DEBT - AFFIL	0.00	(111,793,019.93)	10,894,775.01	(148.61)
INT SHORT TERM DEBT - NON-AFFL	258,775,737.92	0.00	101,586,373.75	8,847,450.86
AMORT OF DEBT DISC, PREM & EXP	6,164,240.50	0.00	0.00	1,492,418.76
AMORT LOSS ON REACQUIRED DEBT	8,196,774.10	0.00	0.00	1,828,824.76
AMORT GAIN ON REACQUIRED DEBT	(1,399,589.54)	0.00	0.00	(137,322.17)
OTHER INTEREST EXPENSE	147,838,003.81	0.00	125,861.33	23,099,391.57
TOTAL INTEREST CHARGES	1,187,960,332.20	(115,331,106.97)	113,214,485.53	150,692,623.90
AFUDC BORROWED FUNDS - CR	(39,378,780.19)	0.00	0.00	(2,692,273.46)
NET INTEREST CHARGES	1,148,581,552.01	(115,331,106.97)	113,214,485.53	148,000,350.44
NET EXTRAORDINARY ITEMS	(34,028,538.94)	0.00	0.00	10,084,051.73
NET INCOME BEFORE PREF DIV	278,031,324.51	(348,226,110.06)	267,067,866.37	73,844,300.42
PREF STK DIVIDEND REQUIREMENT	10,963,432.71	0.00	0.00	2,503,825.16
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	267,067,891.80	(348,226,110.06)	267,067,866.37	71,340,475.26

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO	OPCO CONSOLIDATED
OPERATING REVENUES					
GROSS OPERATING REVENUES	1,356,408,190.43	1,555,245,766.80	410,402,857.30	82,315,179.56	2,227,902,303.90
PROVISION FOR RATE REFUND	0.00	(6,769,380.00)	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	1,356,408,190.43	1,548,476,386.80	410,402,857.30	82,315,179.56	2,227,902,303.90
OPERATING EXPENSES					
OPERATIONS					
FUEL	189,154,849.20	210,869,756.43	74,637,842.87	0.00	771,969,013.64
PURCHASED POWER	347,692,776.12	337,376,083.99	149,344,921.23	59,106,434.24	184,003,501.96
OTHER OPERATION	221,774,841.31	599,012,802.77	53,324,940.07	8,153,760.92	407,375,524.46
MAINTENANCE	69,676,020.41	219,854,438.96	25,865,905.02	1,858,177.32	124,734,687.17
TOTAL OPER/MAINT EXPENSES	828,298,487.04	1,367,113,082.15	303,173,609.19	69,118,372.48	1,488,082,727.23
DEPRECIATION AND AMORTIZATION	99,640,308.61	154,920,168.24	31,027,877.65	3,104,781.77	155,944,265.49
TAXES OTHER THAN INCOME TAXES	123,222,995.98	60,620,947.86	7,251,631.14	3,671,609.98	169,527,397.99
STATE, LOCAL & FOREIGN INCOME TAXES	67,937.00	9,139,787.45	2,457,374.00	426,752.00	(3,974,999.00
FEDERAL INCOME TAXES	109,301,382.18	(8,615,168.00)	16,754,693.00	2,846,046.00	191,495,810.01
TOTAL OPERATING EXPENSES	1,160,531,110.81	1,583,178,817.70	360,665,184.98	79,167,562.23	2,001,075,201.72
NET OPERATING INCOME	195,877,079.62	(34,702,430.90)	49,737,672.32	3,147,617.33	226,827,102.18
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	819,581,176.01	913,556,269.89	351,675,263.72	(11,992.00)	1,268,124,507.09
OTHER INCOME DEDUCTIONS	(806,591,138.41)	(896,141,514.41)	(348,457,873.72)	(132,121.69)	(1,254,312,653.16
TAXES APPL TO OTHER INC &DED	(7,837,148.41)	(7,481,639.13)	(1,147,440.00)	118,219.00	(18,815,152.00
NET OTHR INCOME AND DEDUCTIONS	5,152,889.19	9,933,116.35	2,069,950.00	(25,894.69)	(5,003,298.07
INCOME BEFORE INTEREST CHARGES	201,029,968.81	(24,769,314.55)	51,807,622.32	3,121,722.64	221,823,804.11
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	66,480,089.91	80,130,741.79	25,869,751.08	955,416.70	81,505,646.47
INT SHORT TERM DEBT - AFFIL	1,087,225.87	9,040,307.21	1,806,096.59	676,727.25	3,407,171.58
INT SHORT TERM DEBT - NON-AFFL	1,324,483.98	10,222,431.25	1,488,462.45	228,175.90	5,206,404.46
AMORT OF DEBT DISC, PREM & EXP	673,697.72	1,591,057.95	469,365.90	0.00	1,262,087.28
AMORT LOSS ON REACQUIRED DEBT	2,700,111.17	1,528,277.82	252,578.72	0.00	1,225,431.15
AMORT GAIN ON REACQUIRED DEBT	(170,291.32)	0.00	0.00	0.00	(1,091,976.05
OTHER INTEREST EXPENSE	11,001,041.10	17,236,711.62	1,800,901.15	528,944.24	33,021,883.71
TOTAL INTEREST CHARGES	83,096,358.43	119,749,527.64	31,687,155.89	2,389,264.09	124,536,648.60
AFUDC BORROWED FUNDS - CR	(2,268,554.71)	(12,487,166.08)	(642,646.70)	(53,449.72)	(5,326,629.12
NET INTEREST CHARGES	80,827,803.72	107,262,361.56	31,044,509.19	2,335,814.37	119,210,019.48
NET EXTRAORDINARY ITEMS	(25,236,153.28)	0.00	0.00	0.00	(18,876,437.39
NET INCOME BEFORE PREF DIV	94,966,011.81	(132,031,676.11)	20,763,113.13	785,908.27	83,737,347.24
PREF STK DIVIDEND REQUIREMENT	1,783,084.36	4,623,753.64	0.00	0.00	1,266,014.55
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	93,182,927.45	(136,655,429.75)	20,763,113.13	785,908.27	82,471,332.69

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	WPCO	AEGCO	AEPSC	CCCO	FRECO
OPERATING REVENUES					
GROSS OPERATING REVENUES	87,256,694.35	228,516,457.15	746,396,038.11	0.00	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	87,256,694.35	228,516,457.15	746,396,038.11	0.00	0.00
OPERATING EXPENSES					
OPERATIONS					
FUEL	0.00	102,977,959.12	681,844.01	0.00	0.00
PURCHASED POWER	59,802,224.87	0.00	9,246.51	0.00	0.00
OTHER OPERATION	8,178,323.00	78,578,426.45	597,595,354.02	0.00	0.00
MAINTENANCE	2,753,038.98	9,616,096.16	44,414,701.78	0.00	0.00
TOTAL OPER/MAINT EXPENSES	70,733,586.85	191,172,481.73	642,701,146.32	0.00	0.00
DEPRECIATION AND AMORTIZATION	3,205,233.25	22,161,904.10	4,084,567.91	0.00	0.00
TAXES OTHER THAN INCOME TAXES	4,975,454.17	3,853,951.92	23,235,973.84	0.00	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	223,668.00	1,206,027.00	4,446,779.30	0.00	0.00
FEDERAL INCOME TAXES	2,622,904.00	1,698,234.00	47,966,824.00	0.00	0.00
TOTAL OPERATING EXPENSES	81,760,846.27	220,092,598.75	722,435,291.37	0.00	0.00
NET OPERATING INCOME	5,495,848.08	8,423,858.40	23,960,746.74	0.00	0.00
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	97,885.10	5,966.81	(2,008,787.72)	271,065.08	0.00
OTHER INCOME DEDUCTIONS	(237,505.97)	(28,104.78)	(2,581,922.40)	(249,292.32)	0.00
TAXES APPL TO OTHER INC &DED	109,715.18	3,451,347.00	0.00	(21,340.04)	0.00
NET OTHR INCOME AND DEDUCTIONS	(29,905.69)	3,429,209.03	(4,590,710.12)	432.72	0.00
INCOME BEFORE INTEREST CHARGES	5,465,942.39	11,853,067.43	19,370,036.62	432.72	0.00
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	1,432,873.26	1,894,691.18	5,555,777.52	0.00	0.00
INT SHORT TERM DEBT - AFFIL	148.61	1,123,061.02	1,089,632.54	0.00	0.00
INT SHORT TERM DEBT - NON-AFFL	253,024.33	559,598.20	806,388.49	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	108,456.00	5,213.81	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	239,712.00	421,838.48	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	18,295.13	0.00	11,491,185.78	432.72	0.00
TOTAL INTEREST CHARGES	1,704,341.33	3,925,518.40	19,370,036.62	432.72	0.00
AFUDC BORROWED FUNDS - CR	(29,308.05)	(57,050.87)	0.00	0.00	0.00
NET INTEREST CHARGES	1,675,033.28	3,868,467.53	19,370,036.62	432.72	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	3,790,909.11	7,984,599.90	0.00	(0.00)	0.00
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	3,790,909.11	7,984,599.90	0.00	(0.00)	0.00

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	IFRI	AEPPM	AEPES	AEPINV CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	0.00	0.00	217,037,140.05	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	0.00	217,037,140.05	0.00
OPERATING EXPENSES				
OPERATIONS				
FUEL	0.00	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	117,632,442.71	0.00
OTHER OPERATION	0.00	0.00	75,715,974.87	974,824.13
MAINTENANCE	0.00	0.00	297.96	0.00
TOTAL OPER/MAINT EXPENSES	0.00	0.00	193,348,715.54	974,824.13
DEPRECIATION AND AMORTIZATION	0.00	0.00	1,989,241.02	0.00
TAXES OTHER THAN INCOME TAXES	0.00	0.00	0.00	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	0.00	0.00	0.00
FEDERAL INCOME TAXES	0.00	0.00	0.00	0.00
TOTAL OPERATING EXPENSES	0.00	0.00	195,337,956.56	974,824.13
NET OPERATING INCOME	0.00	0.00	21,699,183.49	(974,824.13)
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	0.00	0.00	1,612,711.75	454,824.96
OTHER INCOME DEDUCTIONS	0.00	0.00	(132,222.02)	(114,154.00)
TAXES APPL TO OTHER INC &DED	0.00	0.00	(6,053,715.07)	219,117.00
NET OTHR INCOME AND DEDUCTIONS	0.00	0.00	(4,573,225.34)	559,787.96
INCOME BEFORE INTEREST CHARGES	0.00	0.00	17,125,958.15	(415,036.17)
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	0.00	0.00	25,465.37	0.00
INT SHORT TERM DEBT - AFFIL	0.00	0.00	3,353,494.79	7,645.99
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	3,718,302.16	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	0.00	229,744.59	0.00
TOTAL INTEREST CHARGES	0.00	0.00	7,327,006.91	7,645.99
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00	0.00
NET INTEREST CHARGES	0.00	0.00	7,327,006.91	7,645.99
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	0.00	0.00	9,798,951.24	(422,682.16)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	0.00	0.00	9,798,951.24	(422,682.16)

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPR CONSOLIDATED	AEPPRO	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC
OPERATING REVENUES					
GROSS OPERATING REVENUES	1,125,035,313.59	23,050,369.75	22,160,318.00	6,161,045,301.00	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	1,125,035,313.59	23,050,369.75	22,160,318.00	6,161,045,301.00	0.00
OPERATING EXPENSES					
OPERATIONS					
FUEL	13,683,077.46	0.00	0.00	1,635,794,105.00	0.00
PURCHASED POWER	809,644,328.97	0.00	0.00	1,452,722,580.00	0.00
OTHER OPERATION	72,049,419.84	28,010,237.18	31,668,556.01	1,351,027,453.00	171,947.09
MAINTENANCE	49,347,933.87	0.00	66,174.59	202,750,703.00	0.00
TOTAL OPER/MAINT EXPENSES	944,724,760.14	28,010,237.18	31,734,730.60	4,642,294,841.00	171,947.09
DEPRECIATION AND AMORTIZATION	56,523,423.45	12,620.16	4,591,218.87	553,322,210.00	0.00
TAXES OTHER THAN INCOME TAXES	7,833,792.18	0.00	213,320.00	191,277,412.00	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	3,620,143.08	0.00	0.00	9,747,615.00	0.00
FEDERAL INCOME TAXES	6,795,671.00	0.00	(1.00)	81,418,665.00	0.00
TOTAL OPERATING EXPENSES	1,019,497,789.85	28,022,857.34	36,539,268.47	5,478,060,743.00	171,947.09
NET OPERATING INCOME	105,537,523.74	(4,972,487.59)	(14,378,950.47)	682,984,558.00	(171,947.09)
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	45,518,622.65	1,525,159.57	(18,029,387.61)	49,753,474.00	0.00
OTHER INCOME DEDUCTIONS	(43,100,527.32)	(1,000.00)	(200,051.12)	0.00	0.00
TAXES APPL TO OTHER INC &DED	11,793,364.64	1,126,802.22	13,379,041.37	(5,083,415.00)	60,697.00
NET OTHR INCOME AND DEDUCTIONS	14,211,459.97	2,650,961.79	(4,850,397.36)	44,670,059.00	60,697.00
INCOME BEFORE INTEREST CHARGES	119,748,983.71	(2,321,525.80)	(19,229,347.83)	727,654,617.00	(111,250.09)
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	87,157,760.46	0.00	4,273,942.54	300,471,612.00	0.00
INT SHORT TERM DEBT - AFFIL	26,166,952.82	0.00	2,462,161.74	50,676,291.00	1,476.52
INT SHORT TERM DEBT - NON-AFFL	3,957,680.05	30,236.87	542,870.17	120,003,855.00	0.00
AMORT OF DEBT DISC, PREM & EXP	561,943.08	0.00	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	2,330.58	597.29	203.00	49,280,480.00	0.00
TOTAL INTEREST CHARGES	117,846,666.99	30,834.16	7,279,177.45	520,432,238.00	1,476.52
AFUDC BORROWED FUNDS - CR	0.00	0.00	(979,600.48)	(14,842,101.00)	0.00
NET INTEREST CHARGES	117,846,666.99	30,834.16	6,299,576.97	505,590,137.00	1,476.52
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	1,902,316.72	(2,352,359.96)	(25,528,924.80)	222,064,480.00	(112,726.61)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	786,755.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	1,902,316.72	(2,352,359.96)	(25,528,924.80)	221,277,725.00	(112,726.61)

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CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	CSWCON ACTUAL DEC 00	CPL ACTUAL DEC 00	PSO ACTUAL DEC 00	SWEPCO ACTUAL DEC 00
Residential	1,501,695,733	649,959,131	360,191,586	327,403,694
Commercial	1,056,274,175	460,433,256	278,940,060	219,318,214
Industrial	907,607,019	370,161,164	198,498,295	273,430,107
Other Ultimate	138,418,228	49,204,477	11,371,868	31,782,330
Base/Fuel Revenue by Customer Class	3,603,995,155	1,529,758,028	849,001,809	851,934,345
Unbilled Revenue	5,583,000	1,621,000	1,661,000	1,469,000
Transmission Access Rev - Affil West	-	4,873,716	(5,959,096)	(1,611,578)
Transmission Access Rev - Nonaffiliated	151,221,966	69,356,470	21,741,044	29,043,835
Loss Compensation Rev - Affil West	-	32,252	288,572	21,403
Other Non KWH	38,723,567	24,864,608	1,882,425	2,561,381
ULTIMATE REVENUE	3,799,523,688	1,630,506,074	868,615,754	883,418,386
Sales for Resale-Nonaffiliated Firm	313,318,664	67,708,944	6,393,114	118,713,815
Sales for Resale-Nonaffiliated Off-Sys	181,768,184	40,373,108	60,272,296	57,362,550
Sales for Resale - Affiliated West	-	35,936,930	29,317,690	67,723,858
Sales for Resale - Affiliated East	(9,461,611)	(3,347,579)	(1,989,924)	(3,007,827)
SALES FOR RESALE	485,625,237	140,671,403	93,993,176	240,792,396
TOTAL ELECTRIC REVENUE	4,285,148,925	1,771,177,477	962,608,930	1,124,210,782
UK Distribution Revenue	350,003,296	0	0	0
UK Supply Revenue	1,170,579,580	0	0	0
UK Powerlink Revenue	64,887,734	0	0	0
UK Non-Core Revenue	267,088,643	-	0	0
UK Intercompany Revenue	(256,780,555)	0	0	0
UK REVENUE	1,595,778,698	-	0	0
Other Non-Utility Rev-Nonaffiliate	280,117,678	-	-	-
Other Non-Utility Rev - Affiliated West	-	-	-	-
OTHER DIVERSIFIED REVENUE	280,117,678	-	-	-
TOTAL REVENUE	6,161,045,301	1,771,177,477	962,608,930	1,124,210,782
Fuel Expense	1,635,794,105	550,903,070	402,933,438	498,803,779
Purchased Power-Nonaffiliated Firm	75,366,910	3,000,184	20,875,240	51,491,486
Purchased Power-Nonaffiliated Off-Sys	298,687,003	141,795,501	73,423,105	13,657,917
Purchased Power - Affiliated West	-	32,339,683	38,571,411	12,643,371
Purchased Power - Affiliated East	22,538,750	251,180	22,216,780	-
FUEL AND PURCHASED POWER	2,032,386,768	728,289,618	558,019,974	576,596,553
UK Distribution Cost of Sales	34,810,755	0	0	0
UK Supply Cost of Sales	1,015,866,856	0	0	0
UK Powerlink Cost of Sales	49,443,277	0	0	0
UK Non-Core Cost of Sales	183,509,125	0	0	0
UK Intercompany Cost of Sales	(227,500,096)	0	0	0
UK COST OF SALES	1,056,129,917	0	0	0
Other Diversified Cost of Sales	7,505,356	0	0	0
Other Production	116,723,312	51,308,777	20,328,440	30,189,224
Transmission	44,429,135	21,282,370	8,811,038	6,002,961
Transmission Access Exp - Affil West	111,720	2,347,621	(2,657,030)	6,627,893
Transmission Access Exp - Nonaffiliated	69,417,792	53,003,311	2,272,900	401,085
Distribution	175,067,208	21,677,614	14,988,686	13,370,189
UK Supply	100,550,048	0	0	0
UK Powerlink	10,125,787	0	0	0
UK Non-Core	57,855,008	0	0	0
UK Intercompany	(28,766,856)	0	0	0
Customer Accounting & Collecting	76,916,603	43,303,902	24,773,884	25,443,104
Customer Service	31,551,875	10,509,456	7,310,606	8,631,921
Sales Expense	4,230,549	14,223	5,231	6,743
Nuclear Decommissioning	8,028,636	8,028,636	-	-
Other Non-Utility Expense	235,189,639	-	-	-
Total Administrative & General	442,091,641	108,063,578	45,863,580	68,786,313
TOTAL OTHER OPERATING EXPENSE	1,343,522,097	319,539,488	121,697,335	159,459,433
Maintenance	202,750,703	60,528,151	45,857,869	75,123,406
TOTAL O & M	1,546,272,800	380,067,639	167,555,204	234,582,839