
**UNITED STATES
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, 2003

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

<u>Commission File Number</u>	<u>Registrants; States of Incorporation; Address and Telephone Number</u>	<u>I.R.S. Employer Identification Nos.</u>
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) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 716-1000	72-0323455

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. ☒

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☒ No ☐

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 accelerated filers (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). 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:

<u>Registrant</u>	<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
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	9.25% Equity Units.....	New York Stock Exchange
Columbus Southern Power Company	None	
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	6% Senior Notes, Series D, Due 2032	New York Stock Exchange
Kentucky Power Company	None	
Ohio Power Company	7 3/8% Senior Notes, Series A, Due 2038	New York Stock Exchange
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	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
Southwestern Electric Power Company	None	

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

<u>Registrant</u>	<u>Title of each class</u>
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

	<u>Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants at June 30, 2003</u>	<u>Number of shares of common stock outstanding of the registrants at December 31, 2003</u>
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.	\$11,782,905,274	395,016,421 (\$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).

DOCUMENTS INCORPORATED BY REFERENCE

<u>Description</u>	<u>Part of Form 10-K Into Which Document Is Incorporated</u>
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2003: 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 2004 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2003	Part III
Portions of Information Statements of the following companies for 2004 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2003: 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.

TABLE OF CONTENTS

	<u>Page Number</u>
Glossary of Terms	i
Forward-Looking Information.....	1
PART I	
Item 1. Business	2
Item 2. Properties	26
Item 3. Legal Proceedings.....	29
Item 4. Submission of Matters to a Vote of Security Holders.....	29
Executive Officers of the Registrants	30
PART II	
Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	31
Item 6. Selected Financial Data	31
Item 7. Management’s Financial Discussion and Analysis and Financial Condition	32
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	32
Item 8. Financial Statements and Supplementary Data.....	32
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	32
Item 9A. Controls and Procedures	32
PART III	
Item 10. Directors and Executive Officers of the Registrants.....	33
Item 11. Executive Compensation	34
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	34
Item 13. Certain Relationships and Related Transactions.....	36
Item 14. Principal Accountant Fees and Services	36
PART IV	
Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K	37
Signatures	39
Index to Financial Statement Schedules	S-1
Independent Auditors’ Report	S-2
Exhibit Index	E-1

GLOSSARY OF TERMS

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

<u>Abbreviation or Acronym</u>	<u>Definition</u>
AEGCo.....	AEP Generating Company, an electric utility subsidiary of AEP
AEP.....	American Electric Power Company, Inc.
AEPES.....	AEP Energy Services, Inc., a subsidiary of AEP
AEP Power Pool.....	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPR.....	AEP Resources, Inc., a subsidiary of AEP
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. 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.
ALJ.....	Administrative law judge
APCo.....	Appalachian Power Company, an electric utility subsidiary of AEP
Btu.....	British thermal unit
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
Centrica.....	Centrica U.S. Holdings, Inc., and its affiliates collectively, unaffiliated companies
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, owned by I&M, 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
DP&L.....	The Dayton Power and Light Company, an unaffiliated utility company
East zone public utility subsidiaries.....	APCo, CSPCo, I&M, KPCo and OPCo
ECOM.....	Excess cost over market
EMF.....	Electric and Magnetic Fields
EPA.....	United States Environmental Protection Agency
ERCOT.....	Electric Reliability Council of Texas
EWG.....	Exempt wholesale generator, as defined under PUHCA
FERC.....	Federal Energy Regulatory Commission
Fitch.....	Fitch Ratings, Inc.
FPA.....	Federal Power Act
FUCO.....	Foreign utility company as defined under PUHCA
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
KPSC.....	Kentucky Public Service Commission
LLWPA.....	Low-Level Waste Policy Act of 1980
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.
MTM.....	Marked-to-market
MW.....	Megawatt
NOx.....	Nitrogen oxide

<u>Abbreviation or Acronym</u>	<u>Definition</u>
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 44.2% equity interest
PJM	PJM Interconnection, L.L.C.
Pro Serv	AEP Pro Serv, Inc., a subsidiary of AEP
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PTB	Price to beat, as defined by the Texas Act
PUCO	The Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935, as amended
QF	Qualifying facility, as defined under the Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Retail electricity provider
Rockport Plant	A generating plant, consisting of two 1,300,000-kilowatt coal-fired generating units, near Rockport, Indiana
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
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 TCC
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
TVA	Tennessee Valley Authority
Virginia Act	Virginia electric restructuring legislation
VSCC	Virginia State Corporation Commission
WVPSC	West Virginia Public Service Commission
West zone public utility subsidiaries	PSO, SWEPCo, TCC and TNC

FORWARD-LOOKING INFORMATION

These reports made by AEP and its registrant subsidiaries contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and 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.
- Available sources and costs of fuels.
- Availability of generating capacity and the performance of AEP's generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- New legislation and government regulation including requirements for reduced emissions of sulfur, nitrogen, carbon and other substances.
- Resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.)
- AEP's ability to reduce its operation and maintenance costs.
- The success of disposing of investments that no longer match AEP's corporate profile.
- AEP's ability to sell assets at attractive prices and on other attractive terms.
- International and country-specific developments affecting foreign investments including the disposition of any current foreign investments.
- The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- AEP's ability to develop and execute on a point of view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt and preferred stock.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including the establishment of a regional transmission structure.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of AEP's pension plan.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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 registered public utility holding company under PUHCA 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, as a single integrated electric utility system. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public 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. Restructuring legislation in Michigan, Ohio, Texas and Virginia has caused or will cause 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, 2003, the subsidiaries of AEP had a total of 22,075 employees. AEP, because it is a holding company rather than an operating company, 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 929,000 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, 2003, APCo and its wholly owned subsidiaries had 2,371 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.

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 698,000 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, 2003, CSPCo had 1,125 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, transmission and distribution of electric power to approximately 575,000 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, 2003, I&M had 2,634 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.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 175,000 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, 2003, KPCo had 394 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.

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. It purchases electric power from APCo for distribution to its customers. At December 31, 2003, Kingsport Power Company had 57 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 704,000 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, 2003, OPCo had 2,153 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, transmission and distribution of electric power to approximately 505,000 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, 2003, PSO had 1,067 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.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 439,000 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, 2003, SWEPCo had 1,351 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.

TCC (organized in Texas in 1945) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 711,000 retail customers through REPs in southern 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, 2003, TCC had 1,203 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 190,000 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, 2003, TNC had 472 employees. The principal industry served by TNC is agriculture. 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.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. Wheeling Power Company does not own any generating facilities. It purchases electric power from OPCo for distribution to its customers. At December 31, 2003, Wheeling Power Company had 57 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 its public utility subsidiaries are all employees of AEPSC. At December 31, 2003, AEPSC had 6,215 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, 2003 are as follows:

	<u>AEP System(a)</u>	<u>APCo</u>	<u>CSPCo</u> (in thousands)	<u>I&M</u>	<u>KPCo</u>
Utility Operations:					
Retail Sales					
Residential.....	\$ 3,171,000	\$ 623,435	\$ 509,919	\$ 352,710	\$ 120,001
Commercial.....	2,348,000	321,515	455,304	272,319	68,904
Industrial.....	1,977,000	342,593	133,242	319,783	94,567
Other Retail Sales.....	<u>173,000</u>	<u>41,060</u>	<u>17,975</u>	<u>6,154</u>	<u>926</u>
Total Retail.....	7,669,000	1,328,603	1,116,440	950,966	284,398
Wholesale					
System Sales and Transmission.....	2,554,000	311,056	183,490	337,275	69,451
Other Wholesale Revenues.....	-	-	-	-	-
Risk Management Realized.....	205,000	17,391	10,491	11,440	4,038
Risk Management Mark-to-Market.....	<u>(198,000)</u>	<u>(2,249)</u>	<u>(5,134)</u>	-	-
Total Wholesale.....	2,561,000	326,198	188,847	348,715	73,489
Other Operating Revenues.....	745,000	79,583	42,195	46,712	18,775
Sales to Affiliates.....	-	<u>222,793</u>	<u>84,369</u>	<u>249,203</u>	<u>39,808</u>
Gross Utility Operations.....	10,975,000	1,957,177	1,431,851	1,595,596	416,470
Provision for Rate Refund.....	<u>(104,000)</u>	<u>181</u>	-	-	-
Net Utility Operations.....	10,871,000	1,957,358	1,431,851	1,595,596	416,470
Investments- Gas Operations.....	3,097,000	-	-	-	-
Investments- Other.....	<u>577,000</u>	-	-	-	-
Total Revenues.....	<u>\$ 14,545,000</u>	<u>\$ 1,957,358</u>	<u>\$ 1,431,851</u>	<u>\$ 1,595,596</u>	<u>\$ 416,470</u>
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u> (in thousands)	<u>TCC</u>	<u>TNC</u>
Utility Operations:					
Retail Sales					
Residential.....	\$ 474,323	\$ 402,988	\$ 350,386	\$ 215,330	\$ 57,191
Commercial.....	314,526	275,852	291,859	158,307	28,395
Industrial.....	522,449	231,638	215,805	43,469	8,199
Other Retail Sales.....	<u>8,413</u>	<u>83,491</u>	<u>6,478</u>	<u>8,824</u>	<u>11,484</u>
Total Retail.....	1,319,711	993,969	864,528	425,930	105,269
Wholesale					
System Sales and Transmission.....	263,397	61,173	147,885	894,509	279,973
Other Wholesale Revenues.....	-	-	-	-	-
Risk Management Realized.....	13,882	3,667	4,325	26,331	9,590
Risk Management Mark-to-Market.....	<u>(11,381)</u>	-	<u>3,439</u>	<u>2,801</u>	<u>911</u>
Total Wholesale.....	265,898	64,840	155,649	923,641	290,474

	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u> (in thousands)	<u>TCC</u>	<u>TNC</u>
Other Operating Revenues.....	74,766	20,883	66,373	339,696	39,292
Sales to Affiliates.....	584,278	23,130	68,854	141,698	51,625
Gross Utility Operations.....	2,244,653	1,102,822	1,155,404	1,830,965	486,660
Provision for Rate Refund	-	-	(8,562)	(83,454)	(20,714)
Net Utility Operations.....	2,244,653	1,102,822	1,146,842	1,747,511	465,946
Investments- Gas Operations	-	-	-	-	-
Investments- Other	-	-	-	-	-
Total Revenues	<u>\$ 2,244,653</u>	<u>\$ 1,102,822</u>	<u>\$ 1,146,842</u>	<u>\$ 1,747,511</u>	<u>\$ 465,946</u>

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated, including AEGCo's total revenues of \$233,165,000 for the year ended December 31, 2003, all of which resulted from its wholesale business, including its marketing and trading of power.

Holding Company Regulation

The provisions of PUHCA, administered by the SEC, regulate many aspects of a registered holding company system, such as the AEP System. PUHCA limits the operations of a registered holding company system 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 utility assets and intra-system transactions.

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.

The Division of Investment Management of the SEC has recommended the conditional repeal of PUHCA. Under its recommendation, certain oversight authority would be transferred to the FERC. Legislation has since been introduced in numerous sessions of Congress that would repeal PUHCA, but such legislation has not passed.

AEP-CSW Merger

On June 15, 2000, CSW (now known as AEP Utilities, Inc.) merged with and into a wholly owned merger subsidiary of AEP. 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 (with respect to PUHCA).

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. The court held that the SEC had not adequately explained its conclusions that the merger met PUHCA requirements that the merging entities be “physically interconnected” and that the combined entity was confined to a “single area or region.”

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

Financing

General

Companies within the AEP System generally use short-term debt to finance working capital needs, acquisitions and construction. The companies periodically issue long-term debt to reduce short-term debt. Short-term debt has in recent history been provided by AEP's commercial paper program and revolving credit facilities. Proceeds were made available to subsidiaries under the AEP corporate borrowing program. Throughout 2003, AEP was successful in accessing the commercial paper market. 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, 2003, 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 2003 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 2003, the rating agencies conducted credit reviews of AEP and its registrant subsidiaries. The agencies also reviewed many companies in the energy sector due to issues that impact the entire industry.

Moody's completed its review of AEP and its rated subsidiaries in February 2003. The results of that review were downgrades of the following ratings for unsecured debt: AEP from Baa2 to Baa3, APCo from Baa1 to Baa2, TCC from Baa1 to Baa2, PSO from A2 to Baa1, SWEPco from A2 to Baa1. TNC, which had no senior unsecured notes outstanding at the time of the ratings action, had its mortgage bond debt downgraded from A2 to A3. AEP's commercial paper was also concurrently downgraded from P-2 to P-3. The completion of this review was a culmination of earlier ratings action in 2002 that had included a downgrade of AEP from Baa1 to Baa2. With the completion of the reviews, Moody's placed AEP and its rated subsidiaries on stable outlook.

S&P completed its review of AEP and its rated subsidiaries in March 2003. The results of that review were downgrades of the ratings for unsecured debt for AEP and its rated subsidiaries from BBB+ to BBB. AEP's commercial paper rating was affirmed at A-2. With the completion of the reviews, S&P placed AEP and its rated subsidiaries on stable outlook.

Fitch completed its review of AEP and its rated subsidiaries in March 2003. The result of that review was a downgrade of AEP's unsecured debt rating from BBB+ to BBB. AEP's commercial paper rating was affirmed at F-2. With the completion of the reviews, Fitch placed AEP and its rated subsidiaries on stable outlook.

See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2003 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit ratings, liquidity and specific financing activities.

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 heading entitled *The Current Air Quality Regulatory Framework*.
- 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. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *The Current Air Quality Regulatory Framework* and *New Source Review Litigation* and Note 9 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2003 Annual Reports, for further information.
- Rules issued by the EPA and certain states that require substantial reductions in SO₂, mercury and NO_x emissions, some of which became effective in 2003. The remaining compliance dates and proposals would take effect periodically through as late as 2018. AEP is installing (or 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 *Future Reduction Requirements for NO_x, SO₂ and Hg* and *Estimated Air Quality Investments* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2003 Annual Reports under the heading entitled *NO_x Reductions* for further information.

- CERCLA, which imposes upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites, costs for environmental remediation. 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 *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2003 Annual Reports, under the heading entitled *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. The EPA recently 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 2003 Annual Reports, under the heading entitled *Clean Water Act Regulation* 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 governed 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*, included in the 2003 Annual Reports, under the heading entitled *Environmental Matters* for information on current 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.

AEP's international operations are subject to environmental regulation 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 named as parties to various legal claims, actions, complaints or other proceedings related to environmental matters. AEP's UK generation facilities will be subject to additional environmental constraints in 2008 (which become more stringent after 2015) because they are subject to regulation governing large combustion plants. In the fourth quarter of 2002, AEP decided not to install certain emission control technology on its Fiddler's Ferry and Ferrybridge generation facilities in 2008. This decision and its legal and regulatory consequences resulted in a significant reduction in the estimated economic life of those facilities. See also *Investments—UK Operations* for a discussion of AEP's planned disposition of these assets in 2004.

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 2003 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 2002 and 2003 and the current estimate for 2004 are shown below. 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 headings entitled *Future Reduction Requirements for NO_x, SO₂ and Hg* and *Estimated Air Quality Investments* Note 7 to the consolidated financial

statements, entitled *Commitments and Contingencies*, included in the 2003 Annual Reports, for more information regarding this litigation and environmental expenditures in general.

	<u>2002 Actual</u>	<u>2003 Actual</u> (in thousands)	<u>2004 Estimate</u>
AEGCo.	\$ 1,200	11,800	9,800
APCo.	108,400	70,600	145,500
CSPCo.	25,400	31,400	18,000
I&M.	1,200	14,900	12,100
KPCo.	110,600	40,500	3,500
OPCo.	110,300	40,000	108,400
PSO.	1,200	1,700	0
SWEPCo.	3,400	3,200	2,700
TCC.	600	500	0
TNC.	1,900	2,600	800
AEP System.	<u>\$ 364,200</u>	<u>\$ 217,200</u>	<u>\$ 300,800</u>

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.

SEC Subpoena, CFTC Complaint and Other Energy Market Investigations

AEP received data requests, subpoenas and information requests from the SEC, CFTC and other state and federal governmental agencies relating to certain energy market investigations. On September 30, 2003, the CFTC filed a complaint against AEP in federal district court alleging that it provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2003 Annual Reports, under the heading *Energy Market Investigations*.

Utility Operations

General

Utility operations constitute the majority 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 approximately 38,000 MW of domestic generation. See *Deactivation and Planned Disposition of Generating Facilities* for a discussion of planned sales of certain of AEP's generating facilities. Pursuant to regulatory orders, the AEP public utility subsidiaries operate their generating facilities as a single interconnected and coordinated electric utility system. 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 operating companies. As of December 31, 2003, the member-load ratios were as follows:

	<u>Peak Demand (MW)</u>	<u>Member-Load Ratio (%)</u>
APCo.	6,873	31.7
CSPCo.	3,871	17.9
I&M.	4,243	19.6
KPCo.	1,564	7.2
OPCo.	5,121	23.6

Although the FERC has approved CSPCo's and OPCo's request to withdraw from the AEP Power Pool as part of its order approving the settlement agreements and AEP's FERC restructuring application, CSPCo and OPCo plan to remain functionally separated through at least December 31, 2008 as provided by their rate stabilization plan filed with the PUCO. See *Management's Financial Discussion and Analysis and Financial Condition*, under the heading entitled *Corporate Separation*, included in the 2003 Annual Reports and Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring*, included in the 2003 Annual Reports, for a discussion of AEP's corporate separation plan.

The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement and AEP System Interim Allowance Agreement during the years ended December 31, 2001, 2002 and 2003:

	<u>2001</u>	<u>2002</u>	<u>2003</u>
		(in thousands)	
APCo.	\$ 256,700	\$ 127,000	\$ 218,000
CSPCo.	251,200	267,000	276,800
I&M.	(166,200)	(113,600)	(118,800)
KPCo.	27,600	46,500	38,400
OPCo.	(369,300)	(326,900)	(414,400)

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 are shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. Upon the sale of its generation assets, TCC 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, 2001, 2002 and 2003:

	<u>2001</u>	<u>2002</u>	<u>2003</u>
		(in thousands)	
PSO.	\$ 6,500	\$ 53,700	\$ 44,000
SWEPCo.	(62,300)	(67,800)	(46,600)
TCC.	13,500	(15,400)	(29,500)
TNC.	42,300	29,500	32,100

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, 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, Virginia and the ERCOT area of Texas, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation. See *Regulation — Rates*.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any public utility subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary. See *Risk Management and Trading* 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 within each zone.

Risk Management and Trading

AEPSC, as agent for AEP's public utility subsidiaries, sells excess power into the market and engages in power and natural gas 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) 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, 2003, counterparties have posted approximately \$45 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries. 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:

	<u>2001</u>	<u>2002</u>	<u>2003</u>
Coal	74%	78%	80%
Natural Gas	12%	8%	7%
Nuclear	11%	11%	9%
Hydroelectric and other.....	3%	3%	4%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages. 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 of certain gas-fired plants owned by TCC and TNC.

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. Management believes, but cannot provide assurances that, AEP's public utility subsidiaries will be able to secure coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. See *Investments-Other* for a discussion of AEP's coal marketing and transportation operations.

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

	<u>2001</u>	<u>2002</u>	<u>2003</u>
Total coal delivered to AEP operated plants (thousands of tons)	73,889	76,442	76,042
Average price per ton of spot-purchased coal.....	\$27.30	\$27.06	\$28.91

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 which may interrupt

deliveries. At December 31, 2003, the System's coal inventory was approximately 42 days of normal usage. This estimate assumes that the total supply would be utilized through the operation of plants that use coal most efficiently.

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 allocate coal and to require the transportation thereof, for the use of power plants or major fuel-burning installations.

Natural Gas: AEP, through its public utility subsidiaries, consumed over 138 billion cubic feet of natural gas during 2003 for generating power. A majority of the gas-fired power plants are connected to at least two natural gas pipelines, which provides greater access to competitive supplies and improves reliability. A portfolio of long-term and short-term 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 and STPNOC have made commitments to meet certain of the nuclear fuel requirements of the Cook Plant and STP, respectively. 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. TCC and the other STP participants have entered into contracts with suppliers for (i) 100% of the uranium concentrate sufficient for the operation of both STP units through spring 2006 and (ii) 50% of the uranium concentrate needed for STP through spring 2007. See *Deactivation and Planned Disposition of Generation Facilities* for more information about TCC's interest in STP.

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.

Nuclear Waste and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of spent nuclear fuel and decommission and decontaminate the plants. 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; and
- Approval of the Cook Plant's license extension.

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

See *Management's Financial Discussion and Analysis of Results of Operations* and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2003 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 and Texas do not currently have disposal sites for such waste available. AEP cannot predict when such sites may be available, but South Carolina and Utah operate low-level radioactive waste disposal sites and accept low-level radioactive waste from Michigan and Texas. AEP's access to the South Carolina facility is currently allowed through the end of fiscal year 2008. There is currently no set date limiting AEP's access to the Utah facility.

Deactivation and Planned Disposition of Generation Facilities

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 that 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 these studies, ERCOT and AEP mutually agreed to enter into reliability must run agreements to continue operation of these seven plants. With ERCOT's approval, AEP deactivated the remaining nine plants. The agreements allowed ERCOT to terminate the agreement with 90 days notice if the facility was no longer needed to ensure reliability of the electricity grid. ERCOT provided such notice with respect to one TNC plant in August 2003 and the plant was deactivated. AEP and ERCOT agreed to new reliability must run contracts at the remaining six plants through December 2004, subject to the same termination provision.

TCC is conducting an auction to sell all of its generation facilities in Texas to establish the market value of the assets and TCC's stranded costs in accordance with the Texas Act. See *Texas Regulatory Assets and Stranded Cost Recovery and Post-Restructuring Wires Charges*. The competitive bidding process began in June 2003 after the PUCT issued a rule confirming TCC's ability to establish the value of its generation assets and amount of stranded costs by selling the generation assets. The PUCT has engaged a consultant and designated a team to monitor the auction and advise TCC on the sale of its generating assets, including requirements of the Texas Act for establishing stranded costs.

The assets to be sold have a generating capacity of 4,497 MW and include eight gas-fired generating plants, one coal-fired plant, TCC's interest in Oklaunion Power Station, a hydroelectric facility and TCC's interest in STP. TCC has entered into agreements to sell its 7.8% share of Oklaunion Power Station and 25.2% share in STP and is continuing to evaluate bids for its remaining generation assets. See Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring*, included in the 2003 Annual Reports, for more information on the planned disposition of TCC generation facilities.

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. OPCo is entitled to 100% of the power generated by the facility, and is responsible for the fuel and other costs of the facility through 2005. 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.

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. 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, 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 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 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 expires on December 31, 2004.

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. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. 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 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, which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2006. The AEP-affiliated owners of OVEC are evaluating the need for environmental investments related to their ownership interests.

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 342 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 January 23, 2003, was recorded at 1,409,726 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 *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 *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 345 KV and above) and certain facilities operated at lower voltages (138 KV and above). 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, 2003, the member-load ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo.....	6,873	31.7
CSPCo.....	3,871	17.9
I&M.....	4,243	19.6
KPCo.....	1,564	7.2
OPCo.....	5,121	23.6

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2001, 2002 and 2003:

	2001	2002	2003
		(in thousands)	
APCo.....	\$ (3,100)	\$ (13,400)	\$ 0
CSPCo.....	40,200	42,200	38,200
I&M.....	(41,300)	(36,100)	(39,800)
KPCo.....	(4,600)	(5,400)	(5,600)
OPCo.....	8,800	12,700	7,200

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (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, 2001, 2002 and 2003:

	2001	2002	2003
		(in thousands)	
PSO.....	\$ 4,000	\$ 4,200	\$ 4,200
SWEPCo.....	5,400	5,000	5,000
TCC.....	(3,900)	(3,600)	(3,600)
TNC.....	(5,500)	(5,600)	(5,600)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries and other System companies also provide transmission services for non-affiliated companies. See *Regional Transmission Organizations*. AEP's public utility subsidiaries are subject to regulation by the FERC under the FPA in respect of transmission of electric power.

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 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 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.

AEP is required, as a condition of FERC's approval in 2000 of AEP's merger with CSW, to transfer functional control of its transmission facilities to one or more RTOs. In May 2002, AEP announced an agreement with PJM to pursue terms for its east zone public utility subsidiaries to participate in PJM, a FERC-approved RTO. In July 2002, the FERC tentatively approved AEP subsidiaries' decision to join PJM, subject to certain conditions being met. The satisfaction of these conditions may only be partially within AEP's control.

In December 2002, AEP's public utility subsidiaries filed applications with the state utility commissions of Indiana, Kentucky, Ohio and Virginia requesting approval of the transfer of functional control of transmission assets in those states to PJM. The status of these applications is as follows:

- The IURC conditionally approved the transfer of functional control of I&M's transmission assets to an RTO in September 2003, though the satisfaction of these conditions is not fully within I&M's or AEP's control;
- In July 2003, the KPSC denied KPCo's request to join PJM based on a lack of evidence that it would benefit Kentucky retail customers, but granted KPCo's request for rehearing. KPCo filed a cost/benefit study in December 2003 and a rehearing has been scheduled for April 2004;
- CSPCo and OPCo filed an application seeking approval of their plan to join PJM in December 2002. In addition, a group of complainants have filed a complaint with the PUCO alleging that CSPCo and OPCo have violated Ohio law by not participating in an RTO and seeking (i) a suspension of certain transmission-related charges to customers, (ii) requiring that CSPCo and OPCo continue to offer service at the prices set forth in their 1999 transition plan filing until January 1, 2006 and (iii) a penalty of \$25,000 for each day that CSPCo and OPCo do not participate in an RTO. The PUCO consolidated our application with the complaint in February 2003. The PUCO has stayed the matter pending greater clarification with respect to RTO matters at the FERC and elsewhere;
- In February 2003, the Virginia legislature enacted legislation that would prohibit the transfer of functional control of transmission assets to an RTO until at least July 2004 and thereafter only with VSCC approval. The legislation requires a transfer by January 2005. In January 2004, APCo filed a supplement to its application with the VSCC consisting of a

cost/benefit analysis of its participation in PJM and additional information required by the VSCC. A hearing on APCo's Virginia application is scheduled for July 2004.

In November 2003, the FERC issued an order (i) proposing to exempt AEP's east zone public utility subsidiaries from Kentucky and Virginia laws requiring state approval of the AEP east zone public utility subsidiaries' transfer of functional control of their transmission assets to an RTO and (ii) directing AEP's east zone public utility subsidiaries to join PJM by October 1, 2004. Several issues, including whether the FERC may exempt AEP's east zone public utility subsidiaries from Kentucky and Virginia law preventing them from joining an RTO, have been heard by an administrative law judge. The FERC has directed that an initial decision be issued by the ALJ by March 15, 2004.

SWEPCo and PSO currently intend to transfer functional control of their transmission assets to SPP subject to receipt of appropriate regulatory approvals. In February 2004, the FERC conditionally approved SPP as an RTO. The Arkansas Public Service Commission and LPSC have required filings related to SWEPCo's and PSO's transfer of functional control of transmission facilities to an RTO. 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 2003 Annual Reports and *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *RTO Formation* for a discussion of public utility subsidiary participation in RTOs.

Regional Through and Out Rates

The FERC has proposed to eliminate our ability to collect certain transmission charges associated with the transmission assets of our east zone public utility subsidiaries and implement transitional rates to mitigate the lost revenues for a two-year period commencing May 1, 2004. The FERC did not indicate how or if the lost revenues would be recovered after the expiration of the transitional rates. Management, however, believes that we are entitled to recover costs of owning and operating these facilities, including a reasonable rate of return. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *FERC Order on Regional Through and Out Rates* for more information.

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. Retail sales in Michigan, while still regulated, are now made at unbundled rates. Other states in AEP's service territory have also passed restructuring legislation that has not been implemented or has been repealed. See *Electric Restructuring and Customer Choice Legislation and Rates*. AEP's subsidiaries are also subject to regulation by the FERC under the FPA. I&M and TCC 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. AEP and certain of its subsidiaries are also subject to the broad regulatory provisions of PUHCA administered by the SEC.

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.

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 is no longer provided for in Ohio. Fuel recovery is also limited in the ERCOT area of Texas, but because AEP sold MECPL and MEWTU, 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 a bundled rate approved by the IURC. While rates are set on a cost-of-service basis, utilities may also generally seek to adjust fuel clause rates quarterly. I&M's base rate is capped through December 31, 2004. Its fuel recovery rate was capped through February 29, 2004 but is expected to return to traditional cost recovery.

Ohio: CSPCo and OPCo each operates as a functionally separated utility and provides "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2005. Market-based default retail generation service rates will be determined in accordance with PUCO rules after December 31, 2005, unless 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) is approved by the PUCO, in which case retail generation rates would be determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates will be frozen from their levels as of December 31, 2005 to (i) December 31, 2008 for CSPCo and (ii) December 31, 2007 (December 31, 2008, if the rate stabilization plan is approved) for OPCo. 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 2003 Annual Reports, for more information.

Oklahoma: PSO provides retail electric service in Oklahoma at a bundled rate 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 adjusted quarterly and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods can be recovered when new quarterly factors are established. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports, for information regarding current rate proceedings.

Texas: The Texas Act requires the legal separation of generation-related assets from transmission and distribution assets. TCC and TNC currently operate on a functionally separated basis. In January 2002, TCC and TNC transferred all their retail customers in the ERCOT area of Texas to MECPL, MEWTU and AEP Commercial and Industrial REP (an AEP affiliate). TNC's retail SPP customers were ultimately transferred to Mutual Energy SWEPCo L.P. (an AEP affiliate). 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 Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports, for information on current rate 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 unbundled retail electric service in Virginia. 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.

The Virginia Act capped base rates at their mid-1999 levels until the end of the transition period (July 1, 2007), or sooner if the VSCC finds that a competitive market for generation exists in Virginia. The Virginia Act permits APCo to seek a one-time change to its capped non-generation rates after January 1, 2004. The Virginia Act allows adjustments to fuel rates during the transition period and continues to permit utilities to recover their actual fuel costs, the fuel component of their purchased power costs and certain capacity charges. APCo recovers its generation capacity charges through capped base rates.

West Virginia: APCo and Wheeling Power Company provide retail electric service at bundled rates approved by the WVPSC. A plan to introduce customer choice was approved by the West Virginia Legislature in its 2000 legislative session. However,

implementation of that plan was placed on hold pending necessary changes to the state's tax laws in a subsequent session. Those changes have not been made. Management currently believes that implementation of the plan is unlikely.

While West Virginia generally allows recovery of fuel costs, the most recent proceeding resulted in the suspension of an active fuel clause for APCo and WPCo (though they continue to recover fuel costs through fixed bundled rates). APCo and Wheeling Power Company are currently unable to change the current level of fuel cost recovery, though this ability could be reinstated in a future proceeding.

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

<u>Jurisdiction</u>	<u>Status of Base Rates for</u>		<u>Fuel Clause Rates</u>			<u>Percentage Of AEP System Retail Revenues(1)</u>
	<u>Power Supply</u>	<u>Energy Delivery</u>	<u>Status</u>	<u>Includes</u>	<u>System Sales Profits Shared w/Ratepayers</u>	
Ohio	Frozen through 2005(2)	Distribution frozen through 2007 for OPCo and 2008 for CSP; Transmission frozen through 2005	None	Not applicable	Not applicable	32%
Texas- ERCOT (TCC, TNC)	See footnote 3	Not capped or frozen	Not applicable	Not applicable	Not applicable	9%(3)
Texas- SPP (SWEPCo, TNC)	Not capped or frozen		Active	Fuel and fuel portion of purchased power	Yes, above base levels	5%
Oklahoma	Not capped or frozen		Active	Fuel and fuel portion of purchased power	Yes	13%
Indiana	Capped until 1/1/05(4)		Active	Fuel and fuel portion of purchased power	No	10%
Virginia	Capped until as late as 7/1/07(5)	Capped until as late as 7/1/07(5)	Active	Fuel and fuel portion of purchased power	No	9%
West Virginia	Not capped or frozen		Suspended(6)	Fuel and fuel portion of purchased power	Yes, but suspended	9%
Louisiana	Capped until 6/15/05		Active	Fuel and fuel portion of purchased power	Yes, above base levels	4%
Kentucky(7)	Not capped or frozen		Active	Fuel and fuel portion of purchased power	Yes, above base levels	4%
Arkansas	Not capped or frozen		Active	Fuel and fuel portion of purchased power	Yes, above base levels	2%
Michigan	Capped until 1/1/05(8)	Capped until 1/1/05(8)	Active	Fuel and fuel portion of purchased power	Yes, in some areas	2%
Tennessee	Not capped or frozen		Active	Fuel and fuel portion of purchased power	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, 2003.

- (2) CSPCo and OPCo have filed a rate stabilization plan with the PUCO to establish (after the market development period) a rate stabilization period from January 1, 2006 through December 31, 2008 during which their default retail generation rates would be established pursuant to such filing. The rate stabilization plan would also extend OPCo's distribution rate freeze through the end of 2008.
- (3) Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs which must offer PTB rates until January 1, 2007.
- (4) Capped base rates pursuant to a 1999 settlement with base rate freeze extended pursuant to merger stipulation.
- (5) Base rates are capped until the earlier of July 1, 2007 or a finding by the VSCC that a competitive market for generation exists. One-time change in non-generation rates is allowed in Virginia.
- (6) Expanded net energy clause suspended in West Virginia pursuant to a 1999 rate case stipulation, but subject to change in a future proceeding.
- (7) KPCo applied for an environmental surcharge to recover costs incurred in connection with the installation of emission control equipment and in 2003 the KPSC granted recovery of \$18 million.
- (8) Capped base and fuel rates pursuant to a 1999 settlement and base rates extended pursuant to merger stipulation.

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. The transmission service regulated by FERC is predominantly wholesale transmission service, which is service not associated with bundled electricity sales to retail customers. FERC also regulates unbundled transmission service to retail customers.

Under the FPA, the FERC 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. AEP has market-rate authority from FERC, under which most of its wholesale marketing activity takes place. In November 2001, the FERC issued an order in connection with its triennial review of AEP's market based pricing authority requiring (i) certain actions by AEP in connection with its sales and purchases within its control area and (ii) posting of information related to generation facility status on AEP's website. AEP has appealed this order, and the FERC has issued an order delaying the effective date of the order. This was done in connection with the FERC's adoption of a new test called supply management assessment (SMA). In December 2003, the FERC issued a staff paper discussing alternatives to SMA and held a technical conference in January 2004. See Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2003 Annual Reports, for more information on the current status of this proceeding.

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.

Implementation of legislation enacted in West Virginia to allow retail customers to choose their electricity supplier is on hold. Before West Virginia's choice plan can be effective, tax legislation must be passed to preserve pre-legislation levels of funding for state and local governments. No further legislation has been passed. Management currently believes that implementation of the plan is unlikely. In February 2003, Arkansas repealed its restructuring legislation.

See Note 5 to the consolidated financial statements, entitled *Effects of Regulation*, included in the 2003 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 and Management's Financial Discussion and Analysis and Financial Condition*, included in the 2003 Annual Reports, under the heading entitled *Corporate Separation* for a discussion of AEP's corporate separation plan.

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, 2003, none of I&M's Michigan customers had elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

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 will terminate no later than December 31, 2005), retail customers will receive distribution and, where applicable, 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. CSPCo and OPCo have filed a rate stabilization plan with the PUCO that, among other things, addresses default generation service rates from January 1, 2006 through December 31, 2008. See *Regulation—FERC* for a discussion of FERC regulation of transmission rates and *Regulation—Rates—Ohio* for a discussion of the impact of restructuring on distribution rates. If the PUCO approves the rate stabilization plan filed by CSPCo and OPCo, they will remain functionally separated through at least December 31, 2008.

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 Legislation:

- 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 obtain electricity at generally unregulated rates, except that 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, at the PTB, until certain conditions in the Texas Legislation 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 (the True-Up Proceeding).

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 *Texas Regulatory Asset and Stranded Cost Recovery and Post-Restructuring Wires Charges*.

Virginia Restructuring

The Virginia Act was enacted in 1999 providing for retail choice of generation suppliers to be phased in over the January 1, 2002 to January 1, 2004 period. The Virginia Act 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 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.

Texas Regulatory Assets and Stranded Cost Recovery and Post-Restructuring Wires Charges

TCC and TNC may recover generation-related regulatory assets and plant-related stranded costs. 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. Plant-related 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. The Texas Act allows alternative methods of valuation to determine the fair market value of generation assets, including outright sale, full and partial stock valuation and asset exchanges, and also, for nuclear generation assets, the ECOM model.

The Texas Act further permits utilities to establish a special purpose entity to issue securitization bonds for the recovery of generation-related regulatory assets and, after the 2004 true-up proceeding, the amount of plant-related stranded costs and remaining generation-related regulatory assets not previously securitized. Securitization bonds allow for regulatory assets and plant-related stranded costs to be refinanced with recovery of the bond principal and financing costs ensured through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds. Any plant-related stranded costs or generation-related regulatory assets not recovered through the sale of securitization bonds may be recovered through a separate non-bypassable competitive transition charge to transmission and distribution customers.

Generation-Related Regulatory Assets

In 1999, TCC filed an application with the PUCT to securitize approximately \$1.27 billion of its retail generation-related regulatory assets and approximately \$47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order authorizing issuance of up to \$797 million of securitization bonds including \$764 million for recovery of net generation-related regulatory assets and \$33 million for other qualified refinancing costs. The securitization bonds were issued in February 2002. TCC has included a transition charge in its distribution rates to repay the bonds over a 14-year period. Another \$185 million of regulatory assets are being recovered through distribution rates beginning in January 2002. Remaining generation related regulatory assets of approximately \$195 million will be included in TCC's request to recover stranded costs in the True-Up Proceeding.

Plant-Related Stranded Costs

It is anticipated that TCC will have significant plant-related stranded costs following the planned sale of its generation assets. As noted, stranded costs are ultimately determined in the True-Up Proceeding. The PUCT adopted a rule regarding the timing of the True-Up Proceedings scheduling TNC's filing (which has no generation related stranded costs) in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

2004 True-Up Proceedings

The purpose of the True-Up Proceeding is to (i) quantify and reconcile the amount of plant-related stranded costs and generation-related regulatory assets taking into account amounts that have not been securitized; (ii) conduct wholesale capacity auction true-ups; (iii) establish final fuel recovery balances; (iv) determine the retail clawback component; and (v) quantify unrefunded excess earnings (collectively, the True-Up Adjustment). The True-Up Adjustment will be reflected as either additional charges or credits to retail customers through transmission and distribution rates collected by REPs and remitted to the utility.

After final determination of True-Up Adjustments by the PUCT, TCC may issue securitization bonds in an amount equal to the sum of (i) its plant-related stranded costs (where applicable) and (ii) generation-related regulatory assets, less its generation-related regulatory assets that have been previously securitized. If securitization bonds are not issued to finance all such amounts, TCC will seek recovery of these amounts as well as the other components of the True-Up Adjustments through non-bypassable competition transition charges in transmission and distribution rates.

Plant-Related Stranded Cost Determination: The Texas Legislation authorized the use of several valuation methodologies to quantify plant-related stranded costs in the True-Up Proceeding, including by the sale of assets. TCC intends to sell its generation assets in order to obtain their market value for the purpose of determining plant-related stranded costs for the True-Up Proceeding and comply with the Texas Legislation. In the True-Up Proceeding, the amount of plant-related stranded costs under this market valuation

methodology will be the amount by which net book value of TCC's generating assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

Wholesale Capacity Auction True-Up Component: The PUCT used a computer model or projection, called an ECOM model, to estimate stranded costs related to generation plant assets in the unbundled cost of service proceedings. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports for further discussion. In connection with using the ECOM model to calculate the stranded cost estimate, the PUCT estimated the market power prices that will be received in the competitive wholesale generation market. Any difference between the ECOM model market prices and actual market power prices as measured by generation capacity auctions required by the Texas Legislation during the period of January 1, 2002 through December 31, 2003 will be a component of the True-Up Proceeding, either increasing or decreasing the amount of recovery for TCC. Actual market prices have been lower than the ECOM model market prices. Therefore, TCC recorded a \$480 million regulatory asset and related revenues for 2002 and 2003.

Fuel Recovery Balance Determination: The fuel component will be determined by the amount of fuel costs and expenses the PUCT approves based on a final fuel reconciliation that TCC and TNC have filed. In 2002, TNC filed with the PUCT to reconcile fuel costs and to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the True-Up Proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at \$6.2 million. This balance will be included in TNC's 2004 true-up proceeding. In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 True-Up Proceeding. In February 2004, an ALJ issued recommendations finding a \$205 million over-recovery in this fuel proceeding. See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports, for further discussion. Any over-recovery, plus interest thereon, will be credited to customers as a component of the True-Up Proceeding.

Retail Clawback Component: The Texas Legislation provides for each price to beat (PTB) retail electricity provider (REP) to refund to its affiliated transmission and distribution utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of \$150 per customer). This retail clawback applies only to the (i) residential and (ii) small commercial classes of customers. If 40% of the load for such customer class is served by competitive REPs, the retail clawback is not applied for such class. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT has ruled that this threshold has been met with respect to the small commercial class for each of TCC and TNC. AEP had accrued a total regulatory liability of approximately \$66 million for all obligations related to retail clawback on its REP's books. As a result of the PUCT ruling on the small commercial retail clawback, \$9 million of this regulatory liability was no longer required and was reversed.

Unrefunded Excess Earnings Component: The Texas Legislation provides, as a component of the True-Up Proceeding, for an earnings test each year from 1999 through 2001. The Texas Legislation requires PUCT approval of the annual earnings test calculation. The PUCT has ruled that each of SWEPCo, TCC and TNC has excess earnings and, in certain instances, has ordered a reduction in distribution rates for the purpose of eliminating such excess earnings. AEP has appealed both the methodology of determining excess earnings and the reduction of distribution rates. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports, for further discussion, including the specific amounts in dispute. The PUCT rulings and the reduction in distribution rates effectively removes unrefunded excess earnings as a component to be determined by the True-Up Proceedings. To the extent AEP prevails in its appeal of the reduction in distribution rates, unrefunded excess earnings, as finally determined, would be included in the True-Up Proceedings and result in a reduction of the True-Up Adjustment.

Pursuant to PUCT rules, if total stranded costs determined in the 2004 True-Up Proceeding are less than the amount of previously securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates. The Texas Third Court of Appeals ruled in February 2003 that the Texas Legislation does not contemplate the refunding to customers of negative stranded costs. In addition, the Court ruled that negative stranded costs cannot be offset against other true-up adjustments including final under-recovered fuel amounts. Portions of this ruling have been appealed to the Texas Supreme Court. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2003 Annual Reports, for more information.

Further Securitization Bonds and Wires Charges: After final determination of its stranded costs and other true-up adjustments by the PUCT, TCC expects to issue securitization bonds in the amount of its currently non-securitized plant-related stranded costs and generation-related regulatory assets determined in the 2004 true-up proceeding. The bonds can have a maximum term of 15 years. If securitization bonds are not issued to finance all currently non-securitized plant-related stranded costs and generation-related

regulatory assets, TCC will seek recovery of these amounts as well as its other true-up adjustments, through a non-bypassable competition transition charge in transmission and distribution rates.

For a discussion of recovery of regulatory assets and stranded costs in Ohio and Virginia, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring*, included in the 2003 Annual Reports.

Competition

AEP's public utility subsidiaries have the right (which in some cases is exclusive) to sell electric power at retail within their respective service areas in the states of Arkansas, Indiana, Kentucky, Louisiana, Oklahoma, Tennessee, West Virginia and the SPP area of Texas. In Michigan, Ohio and Virginia, AEP's public utility subsidiaries continue to provide service to customers who have not been offered or have not selected alternate service from competing suppliers. In those states, service is currently being provided according to prescribed rules and rates. In the ERCOT area of Texas, TCC and TNC sell power (through December 31, 2004) to Centrica, which provides PTB service to certain former customers of TCC and TNC and must compete for customers. See *Regulation — Rates* for a description of the setting of rates for power sold at bundled or unbundled state-regulated rates.

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. Legislation has been enacted in Michigan, Ohio, Texas and Virginia that allows for customer choice of generation supplier. Although restructuring legislation has been passed in Oklahoma and West Virginia, it has been delayed indefinitely in Oklahoma and not implemented in West Virginia. In addition, restructuring legislation in Arkansas has been repealed. See *Electric Restructuring Legislation*. Customer choice legislation generally allows competition in the generation and sale of electric power, but not in its transmission and distribution.

See *Management's Financial Discussion and Analysis of Results of Operations* and Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring*, included in the 2003 Annual Reports, for further information with respect to restructuring legislation affecting AEP subsidiaries.

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. 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.

Investments- Gas Operations

AEP, through certain subsidiaries, operates and owns an interest in a significant amount of gas-related assets, including:

- 6,400 miles of natural gas pipelines between two systems;
- 127 billion cubic feet of storage among two facilities;
- Five natural gas processing plants; and
- Certain gas marketing contracts.

AEP, in operating its natural gas assets, enters into transactions for the purchase and sale of natural gas. These transactions involve (i) purchases of natural gas from producers and subsequent sales to end users and local distribution companies, (ii) physical gas transactions along our natural gas pipelines to maximize revenue, based on price differences between various locations along those assets and (iii) physical (some of which involve purchases of gas that is stored in AEP storage assets) and financial transactions to mitigate price volatility risk. Gas transactions are executed (i) with numerous counterparties, (ii) directly with brokers or (iii) through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers and counterparties may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2003, counterparties posted approximately \$224 million in cash, cash equivalents and letters of credit with AEPES to satisfy the counterparties' obligations in connection with natural gas transactions. AEPES posted approximately \$42 million. Since AEP's open gas trading contracts are valued based on changes in gas market prices, our exposures change daily.

AEP's trading and marketing operations are generally limited to risk management and are focused in regions in which AEP owns assets.

AEP acquired its Bammel storage facility (which has approximately 118 billion cubic feet of storage capacity) from Enron Corporation and certain of its subsidiaries. Because Enron and its relevant subsidiary are now bankrupt, the bankruptcy trustee and other third parties have taken and may take additional positions in the bankruptcy proceedings or litigation that seek to limit or compromise our use of this facility. 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 Assets Held and Used*, respectively, included in the 2003 Annual Reports for more information.

During the third quarter of 2003, we selected an advisor to review our options regarding the assets of our gas operations business. In February 2004, we signed a definitive agreement to sell Louisiana Intrastate Gas (which has approximately 2000 miles of pipeline) and intend to complete the sale of the Jefferson Island storage facility (which has approximately 9 billion cubic feet of storage capacity) in 2004. We are considering our options with respect to our Houston Pipe Line and related assets. See Note 10 to the consolidated financial statements entitled *Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2003 Annual Reports for more information.

Investments- UK Operations

AEP, through certain subsidiaries, operates and owns 4,000 MW of power generation facilities in the UK and engaged in the following activities throughout 2003:

- Selling wholesale power in the UK;
- Trading and marketing power transactions, with numerous counterparties, predominantly limited to risk management around assets used or managed by AEP subsidiaries in the UK. Since AEP's open power trading contracts are valued based on changes in market power prices, our exposures change daily; and
- Procuring and transporting coal to fuel AEP's UK generation facilities and for sale to third parties. Its third party transactions exist because transporting coal is more economical in quantities exceeding those required to operate AEP assets. AEP uses financial instruments executed with numerous counterparties to manage the financial risk of these activities. Since AEP's open coal and freight contracts are based on changes in market prices, our exposures change daily.

AEP expects to sell all its UK operations assets and contracts as a going concern, in one or more transactions, by the end of 2004. During the fourth quarter of 2003, AEP selected an advisor for the disposition of its UK business.

Investments- Other

General

AEP, through certain subsidiaries, conducts certain business operations other than those included in other segments in which it uses and manage a portfolio of energy-related assets. Consistent with its business strategy, AEP intends to dispose of many of these non-core assets. The assets currently used and managed include:

- 1,354 MW of domestic and 1,235 MW of international power generation facilities (of which its ownership is approximately 827 MW and 680 MW, respectively);
- Coal mines 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, either existing or to be constructed, at various locations in North America and Europe;
- Holding and/or operating various properties, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Louisiana, Ohio, Pennsylvania and West Virginia; and
- Through MEMCO Barge Line Inc., transporting coal and dry bulk commodities, primarily on the Ohio, Illinois, and Lower Mississippi rivers for AEP, as well as unaffiliated customers. AEP, through certain subsidiaries, owns or leases 7,000 railcars, 1,800 barges, 37 towboats and two coal handling terminals with 20 million tons of annual capacity.

AEP has in the past two years written down the value of certain of these investments. See *Management's Financial Discussion and Analysis of Results of Operations* and Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2003 Annual Reports.

Dow Chemical Cogeneration Facility

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. AEP's subsidiary, OPCo, is entitled to 100% of the facility's capacity and energy over The Dow Chemical Company's requirements and has contracted to sell the power from this facility for twenty years to Tractebel Energy Marketing, Inc. (Tractebel). The power supply contract with Tractebel is in dispute. 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 Assets Held and Used*, respectively, included in the 2003 Annual Reports, for more information.

Item 2. Properties

Generation Facilities

General

At December 31, 2003, 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:

<u>Company</u>	<u>Stations</u>	<u>Coal MW</u>	<u>Natural Gas MW</u>	<u>Hydro MW</u>	<u>Nuclear MW</u>	<u>Lignite MW</u>	<u>Oil MW</u>	<u>Total MW</u>
AEGCo	1(a)	1,300						1,300
APCo	17(b)	5,073		798				5,871
CSPCo	6(e)	2,595						2,595
I&M	10(a)	2,295		11	2,143			4,449
KPCo	1	1,060						1,060
OPCo	8(b)(f)	8,472		48				8,520
PSO	8(c)	1,018	3,139				25	4,182
SWEPCo	9	1,848	1,797			842		4,487
TCC	12(c)(d)(g)	686	3,175	6	630			4,497
TNC	12(c)	377	999				10	1,386
Totals:	84	24,724	9,110	863	2,773	842	35	38,347

(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) PSO, TCC and TNC jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.

(d) Reflects TCC'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) See *Item 1 — Utility Operations — Electric Generation — Deactivation and Planned Disposition of Generation Facilities* for a discussion of TCC's planned disposition of all its generation facilities.

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, 2003 is listed below.

<u>Facility</u>	<u>Fuel</u>	<u>Location</u>	<u>Capacity Total MW</u>	<u>Ownership Interest</u>	<u>Status</u>
Brush II (a)	Natural gas	Colorado	68	47.75%	QF
Desert Sky Wind Farm	Wind	Texas	161	100%	EWG
Mulberry	Natural gas	Florida	120	46.25%	QF
Orange Cogen	Natural gas	Florida	103	50%	QF
Sweeny	Natural gas	Texas	480	50%	QF
Thermo Cogeneration (a)	Natural gas	Colorado	272	50%	QF
Trent Wind Farm	Wind	Texas	150	100%	EWG
Total U.S.			1,354		
Bajio	Natural gas	Mexico	605	50%	FUCO
Ferrybridge (b)	Coal	United Kingdom	2,000	100%	FUCO
Fiddler's Ferry (b)	Coal	United Kingdom	2,000	100%	FUCO
Nanyang (a)	Coal	China	250	70%	FUCO
Southcoast (a)	Natural gas	United Kingdom	380	50%	FUCO
Total International			5,235		

(a) See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2003 Annual Reports, for a discussion of AEP's planned use and/or disposition of independent power producer and foreign generation assets.

(b) Ferrybridge and Fiddler's Ferry are properties that have been designated as discontinued operations and intended to be sold in 2004. See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2003 Annual Reports, for more information.

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	1,036,000	1,107,000	1,250,600	1,250,600
Net Capacity Factors				
2003 (c)	73.5%	74.5%	62.0%	81.2%
2002	86.6%	80.5%	99.2%	75.0%
2001 (d)	87.3%	83.4%	94.4%	87.1%

(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 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 an alewife fish intrusion.

(d) 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.

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 construction and operation of nuclear facilities. I&M and TCC 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 TCC 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 *Item 1 — Utility Operations — Electric Generation — Planned Deactivation and Planned Disposition of Generation Facilities* for a discussion of TCC's planned disposition of its interest in STP.

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, I&M, TCC and other AEP System companies. See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, incorporated by reference in Item 8, for information with respect to nuclear incident liability insurance.

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 765,000-volt lines:

	<u>Total Overhead Circuit Miles of Transmission and Distribution Lines</u>	<u>Circuit Miles of 765,000-volt Lines</u>
AEP System (a).....	216,685(b)	2,026
APCo.....	50,969	644
CSPCo. (a)	14,016	—
I&M	21,957	615
Kingsport Power Company	1,338	—
KPCo.....	10,703	258
OPCo.....	30,559	509
PSO	21,531	—
SWEPCo.	20,879	—
TCC.....	29,424	—
TNC	13,622	—
Wheeling Power Company	1,688	—

(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 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 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 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

Legislation in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, 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.

Construction Program

General

The AEP System, with input from its state utility commissions, 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. Thus, System reinforcement plans are subject to change, particularly with the restructuring of the electric utility industry.

Proposed Transmission Facilities

APCo is proceeding with its plan to build the Wyoming-Jacksons Ferry 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. APCo must still receive additional federal permits, but does not expect that obtaining these will negatively affect its ability to complete construction.

Construction Expenditures

The following table shows construction expenditures (including environmental expenditures) during 2001, 2002 and 2003 and current estimates of 2004 construction expenditures, in each case including AFUDC but excluding assets acquired under leases.

	<u>2001</u> <u>Actual</u>	<u>2002</u> <u>Actual</u>	<u>2003</u> <u>Actual</u>	<u>2004</u> <u>Estimate</u>
	(in thousands)			
AEP System (a).....	\$ 1,832,000	\$ 1,709,800	\$ 1,358,400	\$ 1,531,300
AEGCo.	6,900	5,300	22,200	18,400
APCo.	306,000	276,500	288,800	405,900
CSPCo.	132,500	136,800	136,300	130,300
I&M	91,100	159,400	184,600	185,600
KPCo.	37,200	178,700	81,700	36,100
OPCo.	344,600	354,800	249,700	303,800
PSO.....	124,900	89,400	86,800	80,100
SWEPCo.....	112,100	111,800	121,100	99,600
TCC	194,100	151,500	141,800	150,500
TNC	39,800	43,600	46,700	57,800

(a) Includes expenditures of other subsidiaries not shown. Amounts in 2001 and 2002 include construction expenditures related to entities classified in 2003 as discontinued operations. These amounts were \$186,500,000 and \$24,900,000, respectively.

See Note 7 to the consolidated 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.

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 March 1, 2004.

<u>Name</u>	<u>Age</u>	<u>Office (a)</u>
Michael G. Morris.....	57	Chairman of the Board, President and Chief Executive Officer of AEP and of AEPSC
Thomas V. Shockley, III.....	58	Vice Chairman of AEP and Vice Chairman and Chief Operating Officer of AEPSC
Henry W. Fayne.....	57	Vice President of AEP, Executive Vice President of AEPSC
Thomas M. Hagan.....	59	Executive Vice President-Shared Services of AEPSC
Holly K. Koepfel.....	45	Executive Vice President of AEPSC
Robert P. Powers.....	50	Executive Vice President- Generation of AEPSC
Susan Tomasky.....	50	Vice President of AEP, Executive Vice President-Policy, Finance and Strategic Planning of AEPSC

(a) Messrs. Fayne and 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. Prior to joining AEPSC in June 2000 as Senior Vice President-Governmental Affairs, Mr. Hagan was Senior Vice President-External Affairs of CSW (1996-2000). Prior to joining AEPSC in July 2000 as Vice President-New Ventures, Ms. Koepfel was Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International (1996-2000). Messrs. Hagan and Powers, Ms. Koepfel 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. Prior to joining AEPSC 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). Prior to 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). 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 March 1, 2004, 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.

<u>Name</u>	<u>Age</u>	<u>Position (a)(b)</u>	<u>Period</u>
Michael G. Morris (a)(b).....	57	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
Thomas V. Shockley, III (a).	58	Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2000-Present
		Chief Operating Officer of AEPSC	2001-Present
		Vice Chairman of AEP and AEPSC	2000-Present
		President and Chief Operating Officer of CSW	1997-2000
		Executive Vice President of CSW	1990-1997
Henry W. Fayne (a).....	57	President of APCo, I&M, OPCo, SWEPCo and TCC	2001-Present
		Director of SWEPCo and TCC	2000-Present
		Director of APCo	1995-Present
		Director of OPCo	1993-Present
		Director of I&M	1998-Present
		Vice President of SWEPCo and TCC	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 AEPSC	2001-Present

<u>Name</u>	<u>Age</u>	<u>Position (a)(b)</u>	<u>Period</u>
Thomas M. Hagan (a)	59	Executive Vice President-Finance and Analysis of AEPSC	2000-2001
		Executive Vice President-Financial Services of AEPSC	1998-2000
		Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2002-Present
		Executive Vice President-Shared Services of AEPSC	2002-Present
		Senior Vice President-Governmental Affairs of AEPSC	2000-2002
Holly K. Koepfel.....	45	Senior Vice President-External Affairs of CSW	1996-2000
		Executive Vice President of AEPSC	2002-Present
		Vice President-New Ventures	2000-2002
Robert P. Powers (a)	50	Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International	1996-2000
		Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2001-Present
		Director of I&M	2001-Present
		Vice President of I&M	1998-Present
		Executive Vice President- Generation	2003-Present
Susan Tomasky (a).....	50	Executive Vice President-Nuclear Generation and Technical Services of AEPSC	2001-2003
		Senior Vice President-Nuclear Operations of AEPSC	2000-2001
		Senior Vice President-Nuclear Generation of AEPSC	1998-2000
		Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of AEPSC	2001-Present
		Executive Vice President-Legal, Policy and Corporate Communications and General Counsel of AEPSC	2000-2001
		Senior Vice President and General Counsel of AEPSC	1998-2000

(a) Messrs. Fayne, Hagan, Morris, Powers and Shockley and Ms. Tomasky are directors of AEGCo, CSPCo, KPCo, PSO and TNC. Messrs. Morris and Shockley are also directors of AEP.

(b) Mr. Morris is a director of Cincinnati Bell, Inc., Spinnaker Exploration Co. and Flint Ink.

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 *Common Stock and Dividend Information* in the 2003 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 2003 and 2002 are incorporated by reference to the material under *Statement of Retained Earnings* in the 2003 Annual Reports.

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 2003 Annual Reports.

Item 7. Management's Financial Discussion and Analysis and Financial Condition

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* in the 2003 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* in the 2003 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* in the 2003 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 2003, AEP's management, including the principal executive officer and principal financial officer, evaluated AEP's disclosure controls and procedures relating to the recording, processing, summarization and reporting of information in AEP's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed to ensure that (a) material information relating to AEP, including its consolidated subsidiaries, is made known to AEP's management, including these officers, by other employees of AEP and its subsidiaries, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. AEP's controls and procedures can only provide reasonable, not absolute, assurance that the above objectives have been met.

As of December 31, 2003, these officers concluded that the disclosure controls and procedures in place provide reasonable assurance that the disclosure controls and procedures can accomplish their objectives. AEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as events warrant.

There have not been any changes in AEP's internal controls over financial reporting (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) during the fourth quarter of 2003 that have materially affected, or are reasonably likely to affect, AEP's internal control over financial reporting.

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 2004 annual meeting of shareholders, to be filed within 120 days after December 31, 2003. 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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

SWEPCo and TCC. 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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003. 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, 2004, 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.

<u>Name</u>	<u>Age</u>	<u>Position (a)</u>	<u>Period</u>
K. G. Boyd	52	Director	1997-Present
		Vice President (Appointed) — Fort Wayne Region	
		Distribution Operations	2000-Present
		Indiana Region Manager	1997-2000
John E. Ehler	47	Director	2001-Present
		Manager of Distribution Systems-Fort Wayne District	2000-Present
		Region Operations Manager	1997-2000
Patrick C. Hale	49	Director	2003-Present
		Plant Manager, Rockport Plant	2003-Present
		Energy Production Manager, Rockport Plant	2001-2003
		Energy Production Manager, Mountaineer Plant (APCo)	1997-2001
David L. Lahrman	52	Director and Manager, Region Support	2001-Present
		Fort Wayne District Manager	1997-2001
Marc E. Lewis	49	Director	2001-Present
		Assistant General Counsel of the Service	
		Corporation	2001-Present
		Senior Counsel of AEPSC	2000-2001
		Senior Attorney of AEPSC	1994-2000
Susanne M. Moorman ...	54	Director and General Manager, Community Services	2000-Present
		Manager, Customer Services Operations	1997-2000
John R. Sampson	51	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

(a) Positions are with I&M unless otherwise indicated.

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 Guidelines, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2004 annual meeting of shareholders to be filed within 120 days after December 31, 2003.

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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003.

I&M, SWEPCo and TCC. 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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003.

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 2004 annual meeting of shareholders to be filed within 120 days after December 31, 2003.

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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003.

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.

SWEPCo and TCC. 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 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003.

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, 2004, 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.

<u>Name</u>	<u>Shares (a)</u>	<u>Stock Units (b)</u>	<u>Total</u>
Karl G. Boyd	12,296	248	12,554
E. Linn Draper, Jr.	822,359(c)	125,233	947,592
John E. Ehler	—	—	—
Henry W. Fayne	236,177(d)	13,143	249,320
Thomas M. Hagan	105,943	149	106,092
Patrick C. Hale	3,025	—	3,025
David L. Lahrman	497	—	497
Marc E. Lewis	6,364	—	6,364
Susanne M. Moorman	41	—	41
Michael G. Morris	—	—	—
Robert P. Powers	139,665	1,378	141,043
John R. Sampson	18,005	—	18,005

Thomas V. Shockley, III	345,323(d)(e)	—	345,323
Susan Tomasky	231,300(d)	6,502	237,802
All Directors and Executive Officers	1,920,995(d)(f)	146,653	2,067,648

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed below:

<u>Name</u>	<u>AEP Retirement Savings Plan (Share Equivalents)</u>
Mr. Boyd.....	96
Dr. Draper.....	4,938
Mr. Ehler.....	—
Mr. Fayne.....	6,152
Mr. Hagan.....	3,617
Mr. Hale.....	25
Mr. Lahrman	497
Mr. Lewis.....	1,282
Ms. Moorman	41
Mr. Morris.....	—
Mr. Powers.....	632
Mr. Sampson.....	805
Mr. Shockley.....	7,530
Ms. Tomasky	1,967
All Directors and Executive Officers.....	27,582

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, 12,000; Dr. Draper, 816,666; Mr. Hagan, 91,833; Mr. Hale, 3,000; Mr. Lewis, 5,082; Mr. Powers, 139,033; Mr. Sampson, 17,200; Mr. Shockley, 300,000; and Mr. Fayne and Ms. Tomasky, 229,333.

(b) This column includes amounts deferred in stock units and held under AEP's officer benefit plans.

(c) Includes 661 shares held by Dr. Draper in joint tenancy with a family member.

(d) Does not include, for Messrs. Fayne, and Shockley and Ms. Tomasky, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne and Shockley and Ms. Tomasky 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 496 shares held by family members of Mr. Shockley over which he disclaimed beneficial ownership.

(f) Represents less than 1% of the total number of shares outstanding.

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, 2003:

<u>Plan Category</u>	<u>Number of securities to be issued upon exercise of outstanding options warrants and rights</u> <u>(a)</u>	<u>Weighted average exercise price of outstanding options, warrants and rights</u> <u>(b)</u>	<u>Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))</u> <u>(c)</u>
Equity compensation plans approved by security holders(1)	9,094,241	\$ 33.0294	4,890,143
Equity compensation plans not approved by security holders	0	N/A	0
Total.....	9,094,241	\$ 33.0294	4,890,143

(1) Consists of shares to be issued upon exercise of outstanding options granted under the American Electric Power System 2000 Long-Term Incentive Plan, 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 Accountants Fees and Services

AEP. The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2004 annual meeting of shareholders to be filed within 120 days after December 31, 2003.

APCo and OPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2004 annual meeting of stockholders, to be filed within 120 days after December 31, 2003.

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

Each of the above are 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 2004 annual meeting of shareholders to be filed within 120 days after December 31, 2003. 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, 2002 and 2003, 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 2004 annual meeting of shareholders to be filed within 120 days after December 31, 2003.

	<u>AEGCo</u>		<u>CSPCo</u>		<u>I&M</u>		<u>KPCo</u>	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Audit Fees.....	\$136,100	126,000	385,000	269,900	366,900	540,400	289,000	251,400
Audit-Related Fees	0	0	0	155,000	0	0	0	0
Tax Fees.....	1,000	1,000	349,000	119,000	26,000	231,000	8,000	34,000
All Other Fees.....	0	0	0	0	0	0	0	0

	<u>PSO</u>		<u>SWEPCo</u>		<u>TCC</u>		<u>TNC</u>	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Audit Fees	\$187,300	156,200	212,900	178,700	511,000	446,700	188,900	92,800
Audit-Related Fees	0	0	0	0	0	274,800	0	213,000
Tax Fees	35,000	103,000	89,000	102,000	89,000	125,000	54,000	77,000
All Other Fees	0	0	0	0	0	0	0	0

PART IV

Item 15. 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:

Statements of Income for the years ended December 31, 2003, 2002, and 2001; Statements of Retained Earnings for the years ended December 31, 2003, 2002, and 2001; Balance Sheets as of December 31, 2003 and 2002; Statements of Cash Flows for the years ended December 31, 2003, 2002, and 2001; Statements of Capitalization as of December 31, 2003 and 2002; Combined Notes to Financial Statements; Independent Auditors' Report.

AEP and Subsidiary Companies:

Consolidated Statements of Operations for the years ended December 31, 2003, 2002, and 2001; Consolidated Balance Sheets as of December 31, 2003 and 2002; Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002, and 2001; Consolidated Statements of Common Shareholders' Equity and Comprehensive Income for the years ended December 31, 2003, 2002, and 2001; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 2003 and 2002; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 2003 and 2002; Combined Notes to Consolidated Financial Statements; Independent Auditors' Report.

APCo, CSPCo, I&M, PSO, SWEPCo and TCC:

Consolidated Statements of Income for the years ended December 31, 2003, 2002, and 2001; Consolidated Statements of Comprehensive Income for the years ended December 31, 2003, 2002, and 2001; Consolidated Statements of Retained Earnings for the years ended December 31, 2003, 2002, and 2001; Consolidated Balance Sheets as of December 31, 2003 and 2002; Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002, and 2001; Consolidated Statements of Capitalization as of December 31, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2003 and 2002; Combined Notes to Consolidated Financial Statements; Independent Auditors' Report.

KPCo, OPCo and TNC:

Statements of Income (or Statements of Operations) for the years ended December 31, 2003, 2002, and 2001; Statements of Comprehensive Income for the years ended December 31, 2003, 2002, and 2001; Statements of Retained Earnings for the years ended December 31, 2003, 2002, and 2001; Balance Sheets as of December 31, 2003 and 2002; Statements of Cash Flows for the years ended December 31, 2003, 2002, and 2001; Statements of Capitalization as of December 31, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2003 and 2002; Combined Notes to Financial Statements; Independent Auditors' Report.

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). Independent Auditors' Report

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 and are incorporated herein by reference

E-1

(b) Reports on Forms 8-K:

<u>Company Reporting</u>	<u>Date of Report</u>	<u>Item Reported</u>
CSPCo	December 3, 2003	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements and Exhibits
SWEPCo	October 3, 2003	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements and Exhibits

(c) Exhibits: See Exhibit Index beginning on page 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, Vice President,
Secretary and Chief Financial Officer)

Date: March 10, 2004

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, President, Chief Executive Officer And Director	March 10, 2004
(ii) Principal Financial Officer:		
<u>/s/ SUSAN TOMASKY</u> (Susan Tomasky)	Vice President, Secretary and Chief Financial Officer	March 10, 2004
(iii) Principal Accounting Officer:		
<u>/s/ JOSEPH M. BUONAIUTO</u> (Joseph M. Buonaiuto)	Controller and Chief Accounting Officer	March 10, 2004
(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		
*RICHARD L. SANDOR		
*THOMAS V. SHOCKLEY, III		
*DONALD G. SMITH		
*LINDA GILLESPIE STUNTZ		
*KATHRYN D. SULLIVAN		
*By: <u>/s/ SUSAN TOMASKY</u> (Susan Tomasky, Attorney-in-Fact)		
		March 10, 2004

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
AEP TEXAS CENTRAL COMPANY
AEP TEXAS NORTH COMPANY
APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Vice President)

Date: March 10, 2004

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chairman of the Board, Chief Executive Officer and Director	March 10, 2004
(ii) Principal Financial Officer:		
<u>/s/ SUSAN TOMASKY</u> (Susan Tomasky)	Vice President, Secretary, Chief Financial Officer and Director	March 10, 2004
(iii) Principal Accounting Officer:		
<u>/s/ JOSEPH M. BUONAIUTO</u> (Joseph M. Buonaiuto)	Controller and Chief Accounting Officer	March 10, 2004
(iv) A Majority of the Directors:		
*JEFFREY D. CROSS		
*HENRY W. FAYNE		
*THOMAS M. HAGAN		
*A. A. PENA		
*ROBERT P. POWERS		
*THOMAS V. SHOCKLEY, III		
*STEPHEN P. SMITH		
*By: <u>/s/ SUSAN TOMASKY</u> (Susan Tomasky, Attorney-in-Fact)		
		March 10, 2004

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 10, 2004

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
(i) Principal Executive Officer:		
*MICHAEL G. MORRIS	Chief Executive Officer and Director	March 10, 2004
(ii) Principal Financial Officer:		
<u>/s/ SUSAN TOMASKY</u> (Susan Tomasky)	Vice President, Secretary, Chief Financial Officer and Director	March 10, 2004
(iii) Principal Accounting Officer:		
<u>/s/ JOSEPH M. BUONAIUTO</u> (Joseph M. Buonaiuto)	Controller and Chief Accounting Officer	March 10, 2004
(iv) A Majority of the Directors:		
*K. G. BOYD		
*JOHN E. EHLER		
*HENRY W. FAYNE		
*THOMAS M. HAGAN		
*PATRICK C. HALE		
*DAVID L. LAHRMAN		
*MARC E. LEWIS		
*SUSANNE M. MOORMAN		
*ROBERT P. POWERS		
*JOHN R. SAMPSON		
*THOMAS V. SHOCKLEY, III		
*By: <u>/s/ SUSAN TOMASKY</u> (Susan Tomasky, Attorney-in-Fact)		
		March 10, 2004

INDEX TO FINANCIAL STATEMENT SCHEDULES

INDEPENDENT AUDITORS' REPORT	<u>Page</u> S-2
The following financial statement schedules are included in this report on the pages indicated	
AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-3
AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-3
AEP TEXAS NORTH COMPANY	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-3
APPALACHIAN POWER COMPANY AND SUBSIDIARIES	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-4
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-4
INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-4
KENTUCKY POWER COMPANY	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-5
OHIO POWER COMPANY CONSOLIDATED	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-5
PUBLIC SERVICE COMPANY OF OKLAHOMA	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-5
SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	
Schedule II — Valuation and Qualifying Accounts and Reserves.....	S-6

INDEPENDENT AUDITORS' REPORT

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiaries and the financial statements of certain of its subsidiaries, listed in Item 15 herein, as of December 31, 2003 and 2002, and for each of the three years in the period ended December 31, 2003, and have issued our reports thereon dated March 5, 2004 (which reports express unqualified opinions and include explanatory paragraphs concerning the adoption of new accounting pronouncements in 2002 and 2003); such financial statements and reports are included in the 2003 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of American Electric Power Company, Inc. and subsidiaries and of certain of its subsidiaries, listed in Item 15. 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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) (in thousands)	Deductions(b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 107,578	\$ 55,087	\$ 7,234	\$ 46,214	\$ 123,685
Year Ended December 31, 2002(c)	\$ 68,429	\$ 87,044	\$ 11,767	\$ 59,662	\$ 107,578
Year Ended December 31, 2001(c)	\$ 31,460	\$ 108,760	\$ 20,763	\$ 92,554	\$ 68,429

(a) Recoveries on accounts previously written off.

(b) Uncollectible accounts written off.

(c) 2002 and 2001 amounts have been adjusted to reflect the treatment of LIG and UK generation assets as discontinued operations in AEP's Consolidated Statements of Operations.

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) (in thousands)	Deductions(b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 346	\$ 1,712	\$ —	\$ 348	\$ 1,710
Year Ended December 31, 2002	\$ 186	\$ 162	\$ 1	\$ 3	\$ 346
Year Ended December 31, 2001	\$ 1,675	\$ 186	\$ —	\$ 1,675	\$ 186

(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) (in thousands)	Deductions(b)	Balance at End of Period
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$5,041	\$ 123	\$ —	\$ 4,989	\$ 175
Year Ended December 31, 2002	\$ 196	\$ 4,846	\$ 17	\$ 18	\$ 5,041
Year Ended December 31, 2001	\$ 288	\$ 13	\$ 35	\$ 140	\$ 196

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$13,439	\$ 4,708	\$ 433	\$16,495	\$ 2,085
Year Ended December 31, 2002	\$ 1,877	\$ 3,937	\$ 12,367	\$ 4,742	\$ 13,439
Year Ended December 31, 2001	\$ 2,588	\$ 2,644	\$ 1,017	\$ 4,372	\$ 1,877

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 634	\$ 96	\$ —	\$ 199	\$ 531
Year Ended December 31, 2002	\$ 745	\$ (100)	\$ —	\$ 11	\$ 634
Year Ended December 31, 2001	\$ 659	\$ 331	\$ —	\$ 245	\$ 745

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 578	\$ 37	\$ —	\$ 84	\$ 531
Year Ended December 31, 2002	\$ 741	\$ (161)	\$ —	\$ 2	\$ 578
Year Ended December 31, 2001	\$ 759	\$ 65	\$ 3	\$ 86	\$ 741

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 192	\$ 8	\$ 912	\$ 376	\$ 736
Year Ended December 31, 2002	\$ 264	\$ (68)	\$ —	\$ 4	\$ 192
Year Ended December 31, 2001	\$ 282	\$ —	\$ (24)	\$ (6)	\$ 264

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 909	\$ 42	\$ 18	\$ 180	\$ 789
Year Ended December 31, 2002	\$ 1,379	\$ (457)	\$ —	\$ 13	\$ 909
Year Ended December 31, 2001	\$ 1,054	\$ 554	\$ —	\$ 229	\$ 1,379

(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
Description	Balance at Beginning Of Period	Additions		Deductions(b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts(a) (in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2003	\$ 84	\$ 37	\$ —	\$ 84	\$ 37
Year Ended December 31, 2002	\$ 44	\$ 7	\$ 33	\$ —	\$ 84
Year Ended December 31, 2001	\$ 467	\$ 44	\$ —	\$ 467	\$ 44

(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

<u>Column A</u>	<u>Column B</u>	<u>Column C</u>		<u>Column D</u>	<u>Column E</u>
		<u>Additions</u>			
<u>Description</u>	<u>Balance at</u>	<u>Charged to</u>	<u>Charged to</u>		<u>Balance at</u>
	<u>Beginning</u>	<u>Costs and</u>	<u>Other</u>	<u>Deductions(b)</u>	<u>End of</u>
	<u>Of Period</u>	<u>Expenses</u>	<u>Accounts(a)</u>		<u>Period</u>
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for					
Uncollectible Accounts:					
Year Ended December 31, 2003	<u>\$ 2,128</u>	<u>\$ 103</u>	<u>\$ —</u>	<u>\$ 138</u>	<u>\$ 2,093</u>
Year Ended December 31, 2002	<u>\$ 89</u>	<u>\$ 2,036</u>	<u>\$ 4</u>	<u>\$ 1</u>	<u>\$ 2,128</u>
Year Ended December 31, 2001	<u>\$ 911</u>	<u>\$ 89</u>	<u>\$ —</u>	<u>\$ 911</u>	<u>\$ 89</u>

(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.

<u>Exhibit Number</u>	<u>Description</u>
AEGCo	
3(a)	— 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)	— Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP [Registration Statement No. 33-32752, Exhibit 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, Exhibits 28(b)(1)(A) and 28(b)(1)(B)].
10(b)(2)	— Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KPCo [Registration Statement No. 33-32752, Exhibit 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, 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 2003 Annual Report (for the fiscal year ended December 31, 2003) 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.
AEP†	
3(a)	— 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)	— 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 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)	— By-Laws of AEP, as amended through December 15, 2003.
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, Exhibits 4(a), 4(b) and 4(c); Registration Statement No. 333-105532, Exhibits 4(d), and 4(e) and 4(f)].
4(b)	— Forward Purchase Contract Agreement, dated as of June 11, 2002, between AEP and The Bank of New York, as Forward Purchase Contract Agent [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525, Exhibit 4(c)].

<u>Exhibit Number</u>	<u>Description</u>
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, 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)	— Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(b)].
10(c)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC 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)	— Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(d)].
10(e)	— 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(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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(h)(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(h)(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(i)(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(i)(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(j)	— 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)].
*†10(k)(1)	— AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended December 10, 2003.
*†10(k)(2)	— AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended December 10, 2003.
†10(l)(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(l)(1)(B)	— Guaranty by AEP of AEPSC 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(l)(1)(C)	— First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(l)(1)(c)].
*†10(l)(2)	— AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2003 (Non-Qualified)

<u>Exhibit Number</u>	<u>Description</u>
†10(l)(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(m)(1)	— Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.
†10(m)(2)	— Memorandum of agreement between Susan Tomasky and AEPSC 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(m)(3)	— Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(m)(3)(A)].
†10(m)(4)	— Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(m)(4)].
†10(n)	— 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(o)(1)	— 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(o)(2)	— First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(o)(2)].
†10(p)	— 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(q)	— AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.
†10(r)	— AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(r)].
†10(s)	— Nuclear Key Contributor Retention Plan dated May 1, 2000 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2002, file No. 1-3525; Exhibit 10(s)].
†10(t)	— 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(u)	— AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.
†10(v)(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(v)(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(v)(3)	— Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.
†10(v)(4)	— CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
†10(v)(5)	— Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997 [Annual Report on Form 10-K of CSW for the fiscal year ended December 31, 1998, File No. 1-1443, Exhibit 24].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the AEP 2003 Annual Report (for the fiscal year ended December 31, 2003) 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.

<u>Exhibit Number</u>	<u>Description</u>
*32(b)	— Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
APCo‡	
3(a)	— 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)	— 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)	— 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 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)	— By-Laws of APCo (amended as of October 24, 2001) [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2001, File No. 1-3457, Exhibit 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, 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); Registration Statement No. 333-100451, Exhibit 4(b); and Annual Report on Form 10-K of APCo for fiscal year ended December 31, 2002, File 1-3457, Exhibit 4(c)].
*4(c)	— Company Order and Officer's Certificate, dated May 5, 2003, establishing terms of 3.60% Senior Notes, Series G, due 2008 and 5.95% Senior Notes, Series H, due 2033.
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, 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)	— 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)].

<u>Exhibit Number</u>	<u>Description</u>
10(a)(3)	— 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)	— Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, 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)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC 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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [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)].
†10(h)(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(h)(1)(B)	— First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2002, File No. 1-3457; Exhibit 10(h)(1)(B)].
*†10(h)(2)	— AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2003 (Non-Qualified).
†10(h)(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(i)(1)	— Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.
†10(i)(2)	— Memorandum of agreement between Susan Tomasky and AEPSC 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(i)(3)	— Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2002, File No. 1-3457; Exhibit 10(i)(3)].
†10(j)(1)	— 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(j)(2)	— First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2002, File No. 1-3457; Exhibit 10(j)(2)].
†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, as amended December 10, 2003.

<u>Exhibit Number</u>	<u>Description</u>
†10(n)(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(n)(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(n)(3)	— Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.
†10(n)(4)	— CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
*†10(o)(1)	— AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.
†10(p)	— AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2002, File No. 1-3457; Exhibit 10(p)].
†10(q)	— Nuclear Key Contributor Retention Plan dated May 1, 2000 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 2002, File No. 1-3457; Exhibit 10(q)].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the APCo 2003 Annual Report (for the fiscal year ended December 31, 2003) 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, 2003, File No. 1-3525, Exhibit 21].
*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.
CSPCo‡	
3(a)	— Amended Articles of Incorporation of CSPCo, as amended to March 6, 1992 [Registration Statement No. 33-53377, Exhibit 4(a)].
3(b)	— 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 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)	— 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)].
4(a)	— 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)	— 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)].

<u>Exhibit Number</u>	<u>Description</u>
*4(c)	— First Supplemental Indenture between CSPCo and Deutsche Bank Trust Company Americas, as Trustee, dated November 25, 2003, establishing terms of 4.40% Senior Notes, Series E, due 2010.
*4(d)	— Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee
*4(e)	— First Supplemental Indenture, dated as of February 1, 2003, between CSPCo 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 C, due 2013.
*4(f)	— Second Supplemental Indenture, dated as of February 1, 2003, between CSPCo and Bank One, N.A. establishing the terms of 6.60% Senior Notes, Series B, due 2033 and 6.60% Senior Notes, Series D, due 2033.
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, 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)	— 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)	— 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)	— Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, 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)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC 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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [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 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 2003 Annual Report (for the fiscal year ended December 31, 2003) which are incorporated by reference in this filing.
21	— List of subsidiaries of CSPCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2003, File No. 1-3525, Exhibit 21]
*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.

<u>Exhibit Number</u>	<u>Description</u>
*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.
I&M‡	
3(a)	— 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)	— 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 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)	— By-Laws of I&M (amended as of November 28, 2001) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 2001, File No. 1-3570, Exhibit 3(d)].
4(a)	— 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)	— 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. 333-58656, Exhibits 4(b) and 4(c); Registration Statement No. 333-108975, Exhibits 4(b), 4(c) and 4(d)].
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, 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)	— 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)	— 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)	— 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)].

<u>Exhibit Number</u>	<u>Description</u>
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, 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)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC 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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [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)	— 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)].
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 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 2003 Annual Report (for the fiscal year ended December 31, 2003) 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, 2003, File No. 1-3525, Exhibit 21].
*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.
KPCo‡	
3(a)	— Restated Articles of Incorporation of KPCo [Annual Report on Form 10-K of KPCo for the fiscal year ended December 31, 1991, File No. 1-6858, Exhibit 3(a)].
3(b)	— By-Laws of KPCo (amended as of June 15, 2000) [Annual Report on Form 10-K of KPCo for the fiscal year ended December 31, 2000, File No. 1-6858, Exhibit 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, Exhibits 4(a), 4(b), 4(c) and 4(d); Registration Statement No. 333-87216, Exhibits 4(e) and 4(f); Annual Report on Form 10-K of KPCo for the fiscal year ended December 31, 2002, File No. 1-6858, Exhibits 4(c), 4(d) and 4(e)].
*4(b)	— Company Order and Officer's Certificate, dated June 13, 2003 establishing certain terms of the 5.625% Senior Notes, Series D, due 2032.
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, 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)].

<u>Exhibit Number</u>	<u>Description</u>
10(b)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC 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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
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 KPCo dated December 15, 1999, File No. 1-6858, Exhibit 10].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the KPCo 2003 Annual Report (for the fiscal year ended December 31, 2003) 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.
OPCo‡	
3(a)	— 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)	— 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)	— Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated June 3, 2002 [Quarterly Report on Form 10-Q of OPCo for the quarter ended June 30, 2002, File No. 1-6543, Exhibit 3(d)].
3(e)	— Composite of the Amended Articles of Incorporation of OPCo (amended as of June 3, 2002) [[Quarterly Report on Form 10-Q of OPCo for the quarter ended June 30, 2002, File No. 1-6543, Exhibit 3(e)].
3(f)	— 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)	— 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)].

<u>Exhibit Number</u>	<u>Description</u>
4(b)	— 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, Exhibits 4(a), 4(b) and 4(c); Registration Statement No. 333-106242, Exhibit 4(b), 4(c) and 4(d); Registration Statement No. 333-75783, Exhibits 4(b) and 4(c)].
*4(c)	—First Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 4.85% Senior Notes, Series H, due 2014.
*4(d)	—Second Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 6.375% Senior Notes, Series I, due 2033.
*4(e)	— Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee
*4(f)	— First Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series D, due 2013 and 5.50% Senior Notes, Series F, due 2013.
*4(g)	— Second Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 6.60% Senior Notes, Series E, due 2033 and 6.60% Senior Notes, Series G, due 2033.
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, 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)	— 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)	— 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)	— Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, 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)	— Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC 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)	— Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC [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)	— 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)].

<u>Exhibit Number</u>	<u>Description</u>
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].
†10(h)	— 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(i)(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(i)(1)(B)	— First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2002, File No. 1-6543; Exhibit 10(i)(1)(B)].
*†10(i)(2)	— AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2003 (Non-Qualified).
†10(i)(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(j)(1)	— Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.
†10(j)(2)	— Memorandum of agreement between Susan Tomasky and AEPSC 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(j)(3)	— Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2002, File No. 1-6543; Exhibit 10(j)(3)].
†10(k)(1)	— 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)(2)	— First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2002, File No. 1-6543; Exhibit 10(k)(2)].
†10(l)	— 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(m)	— 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(n)	— AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.
†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)	— Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.
†10(o)(4)	— CSW 1992 Long-Term Incentive Plan [Proxy Statement of CSW, March 13, 1992].
*†10(p)	— AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.
†10(q)	— AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2002, File No. 1-6543; Exhibit 10(q)].
†10(r)	— Nuclear Key Contributor Retention Plan dated May 1, 2000 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 2002, File No. 1-6543; Exhibit 10(r)].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the OPCo 2003 Annual Report (for the fiscal year ended December 31, 2003) 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, 2003, File No. 1-3525, Exhibit 21].
*23	— Consent of Deloitte & Touche LLP.
*24	— Power of Attorney.

<u>Exhibit Number</u>	<u>Description</u>
*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.
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 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: <ul style="list-style-type: none"> (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 [Registration Statement No. 333-100623, Exhibits 4(a) and 4(b); [Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 2002, File No. 0-343; Exhibit 4(c)].
*4(d)	— Third Supplemental Indenture, dated as of September 15, 2003, between PSO and The Bank of New York, as Trustee, establishing terms of the 4.85% Senior Notes, Series C, due 2010.
10(a)	— Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 2002, File No. 0-343; Exhibit 10(a)].
10(b)	— Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 2002, File No. 0-343; Exhibit 10(b)].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the PSO 2003 Annual Report (for the fiscal year ended December 31, 2003) which are incorporated by reference in this filing.
*23	— Consent of Deloitte & Touche LLP.
*24	— Power of Attorney.

<u>Exhibit Number</u>	<u>Description</u>
*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.
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].
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: <ul style="list-style-type: none"> (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 exhibit 4(f)(i)(A).
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, Exhibits 4(a) and 4(b); Registration Statement No. 333-100632, Exhibit 4(b); Registration Statement No. 333-108045 Exhibit 4(b)].
*4(d)	— Third Supplemental Indenture, between SWEPCo and The Bank of New York, as Trustee, dated April 11, 2003, establishing terms of 5.375% Senior Notes, Series C, due 2015.
10(a)	— Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of SWEPCo for the fiscal year ended December 31, 2002, File No. 1-3146; Exhibit 10(a)].
10(b)	— Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of SWEPCo for the fiscal year ended December 31, 2002, File No. 1-3146; Exhibit 10(b)].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the SWEPCo 2003 Annual Report (for the fiscal year ended December 31, 2003) which are incorporated by reference in this filing.
21	— List of subsidiaries of SWEPCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2003, File No. 1-3525, Exhibit 21]
*23	— Consent of Deloitte & Touche LLP.

<u>Exhibit Number</u>	<u>Description</u>
*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.
TCC‡	
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 TCC for the quarter ended March 31, 1997, File No. 0-346, Exhibit 3.1].
3(b)	— Articles of Amendment to Restated Articles of Incorporation of TCC dated December 18, 2002 [Annual Report on Form 10-K of TCC for the fiscal year ended December 31, 2002, File No. 0-346; Exhibit 3(b)].
3(c)	— By-Laws of TCC (amended as of April 19, 2000) [Annual Report on Form 10-K of TCC for the fiscal year ended December 31, 2000, File No. 0-346, Exhibit 3(b)].
4(a)	— Indenture of Mortgage or Deed of Trust, dated November 1, 1943, between TCC 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)	— TCC-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of TCC: <ul style="list-style-type: none"> (1) Indenture, dated as of May 1, 1997, between TCC and The Bank of New York, as Trustee [Quarterly Report on Form 10-Q of TCC dated March 31, 1997, File No. 0-346, Exhibits 4.1 and 4.2]. (2) Amended and Restated Trust Agreement of TCC Capital I, dated as of May 1, 1997, among TCC, 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 TCC dated March 31, 1997, File No. 0-346, Exhibit 4.3]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by TCC for the benefit of the holders of TCC Capital I's Preferred Securities [Quarterly Report on Form 10-Q of TCC 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 TCC and TCC Capital I [Quarterly Report on Form 10-Q of TCC 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 TCC and The Bank of New York, as Trustee, as amended and supplemented [Annual Report on Form 10-K of TCC for the fiscal year ended December 31, 2000, File No. 0-346, Exhibits 4(c), 4(d) and 4(e)].
*4(d)	— Indenture (for unsecured debt securities), dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee
*4(e)	— 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.
*4(f)	— 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.
*4(g)	— 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.

<u>Exhibit Number</u>	<u>Description</u>
*4(h)	— Fourth Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, 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 [Annual Report on Form 10-K of TCC for the fiscal year ended December 31, 2002, File No. 0-346; Exhibit 10(a)].
10(b)	— Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of TCC for the fiscal year ended December 31, 2002, File No. 0-346; Exhibit 10(b)].
*12	— Statement re: Computation of Ratios.
*13	— Copy of those portions of the TCC 2003 Annual Report (for the fiscal year ended December 31, 2003) which are incorporated by reference in this filing.
21	— List of subsidiaries of TCC [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2003, File No. 1-3525, Exhibit 21]
*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.
TNC‡	
3(a)	— Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation [Annual Report on Form 10-K of TNC for the fiscal year ended December 31, 1996, File No. 0-340, Exhibit 3.5].
3(b)	— Articles of Amendment to Restated Articles of Incorporation of TNC dated December 17, 2002 [Annual Report on Form 10-K of TNC for the fiscal year ended December 31, 2002, File No. 0-340; Exhibit 3(b)].
3(c)	— By-Laws of TNC (amended as of May 1, 2000) [Quarterly Report on Form 10-Q of TNC for the quarter ended March 31, 2000, File No. 0-340, Exhibit 3.4].
4(a)	— Indenture, dated August 1, 1943, between TNC 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)].
*4(b)	— Indenture (for unsecured debt securities), dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee
*4(c)	— 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.
10(a)	— Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of TNC for the fiscal year ended December 31, 2002, File No. 0-340; Exhibit 10(a)].
10(b)	— Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC [Annual Report on Form 10-K of TNC for the fiscal year ended December 31, 2002, File No. 0-340; Exhibit 10(b)].
*12	— Statement re: Computation of Ratios.

Exhibit Number**Description**

- | | |
|--------|--|
| *13 | — Copy of those portions of the TNC 2003 Annual Report (for the fiscal year ended December 31, 2003) 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. |

‡ 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.

June 13, 2003

Company Order and Officers' Certificate
5.625% Senior Notes, Series D, due 2032

Deutsche Bank Trust Company Americas, as Trustee
Corporate Trust & Agency Services
280 Park Avenue, MS-NYC03-0914
New York, NY 10017

Ladies and Gentlemen:

Pursuant to Article Two of the Indenture, dated as of September 1, 1997 (as it may be amended or supplemented, the "Indenture"), from Kentucky Power Company (the "Company") to Bankers Trust Company, now Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), and the Board Resolutions dated April 22, 2002, a copy of which certified by the Secretary or an Assistant Secretary of the Company is being delivered herewith under Section 2.01 of the Indenture, and unless otherwise provided in a subsequent Company Order pursuant to Section 2.04 of the Indenture,

1. the Company's 5.625% Senior Notes, Series D, due 2032 (the "Notes") are hereby established. The Notes shall be in substantially the form attached hereto as Exhibit 1.
2. the terms and characteristics of the Notes shall be as follows (the numbered clauses set forth below corresponding to the numbered subsections of Section 2.01 of the Indenture, with terms used and not defined herein having the meanings specified in the Indenture):
 - (i) the aggregate principal amount of Notes which shall initially be authenticated and delivered under the Indenture is \$75,000,000, except as contemplated in Section 2.01(i) of the Indenture;
 - (ii) the date on which the principal of the Notes shall be payable shall be December 1, 2032;

(iii) interest shall accrue from the date of authentication of the Notes; the Interest Payment Dates on which such interest will be payable shall be June 1 and December 1, and the Regular Record Date for the determination of holders to whom interest is payable on any such Interest Payment Date shall be the May 15 or November 15 preceding the relevant Interest Payment Date; provided that the first Interest Payment Date shall be December 1, 2003 and interest payable on the Stated Maturity Date or any Redemption Date shall be paid to the Person to whom principal shall be paid;

(iv) the interest rate at which the Notes shall bear interest shall be 5.625% per annum;

(v) the Notes shall be redeemable at the option of the Company, in whole at any time or in part from time to time, upon not less than thirty but not more than sixty days' previous notice given by mail to the registered owners of the Notes at a redemption price equal to the greater of (i) 100% of the principal amount of the Notes being redeemed and (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Notes being redeemed (excluding the portion of any such interest accrued to the date of redemption) discounted (for purposes of determining present value) to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 30 basis points, plus, in each case, accrued interest thereon to the date of redemption.

"Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

"Comparable Treasury Issue" means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of the Notes that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Notes.

"Comparable Treasury Price" means, with respect to any redemption date, (i) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case a percentage of its principal amount) on the third Business Day preceding such redemption date, as set forth in the daily statistical release (or any successor release) published by the Federal Reserve Bank of New York and designated "Composite 3:30 p.m. Quotations for U. S. Government Securities" or (ii) if such release (or any successor release) is not published or does not contain such prices on such third Business Day, the Reference Treasury Dealer Quotation for such redemption date.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by the Company and reasonably acceptable to the Trustee.

"Reference Treasury Dealer" means a primary U.S. government securities dealer in New York City selected by the Company and reasonably acceptable to the Trustee.

"Reference Treasury Dealer Quotation" means, with respect to the Reference Treasury Dealer and any redemption date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Trustee by such Reference Treasury Dealer at or before 5:00 p.m., New York City time, on the third Business Day preceding such redemption date.

(vi) (a) the Notes shall be issued in the form of a Global Note; (b) the Depositary for such Global Note shall be The Depositary Trust Company; and (c) the procedures with respect to transfer and exchange of Global Notes shall be as set forth in the form of Note attached hereto;

(vii) the title of the Notes shall be "5.625% Senior Notes, Series D, due 2032";

(viii) the form of the Notes shall be as set forth in Paragraph 1, above;

(ix) not applicable;

(x) the Notes may be subject to a Periodic Offering;

(xi) not applicable;

(xii) not applicable;

(xiii) the Company will pay the principal of the Notes and any premium and interest payable at redemption, if any, or at maturity in immediately available funds at the office of Deutsche Bank Trust Company Americas, Corporate Trust and Agency Services, 60 Wall Street, MSNYC 602515, New York, New York 10005;

(xiv) the Notes shall be issuable in denominations of \$1,000 and any integral multiple thereof;

(xv) not applicable;

(xvi) the Notes shall not be issued as Discount Securities;

(xvii) not applicable;

(xviii) not applicable; and

(xix) So long as any of the Notes are outstanding, the Company will not create or suffer to be created or to exist any additional mortgage, pledge, security interest, or other lien (collectively "Liens") on any of its utility properties or tangible assets now owned or hereafter acquired to secure any indebtedness for borrowed money ("Secured Debt"), without providing that the Notes will be similarly secured. This restriction does not apply to the Company's subsidiaries, nor will it prevent any of them from creating or permitting to exist Liens on their property or assets to secure any Secured Debt. Further, this restriction on Secured Debt does not apply to the Company's existing first mortgage bonds that have previously been issued under its Mortgage and Deed of Trust, dated as of May 1, 1949, between the Company and Deutsche Bank Trust Company Americas (formerly Bankers Trust Company), as Trustee or any indenture supplemental thereto; provided that this restriction will apply to future issuances thereunder (other than issuances of refunding first mortgage bonds). In addition, this restriction does not prevent the creation or existence of:

(a) Liens on property existing at the time of acquisition or construction of such property (or created within one year after completion of such acquisition or construction), whether by purchase, merger, construction or otherwise, or to secure the payment of all or any part of the purchase price or construction cost thereof, including the extension of any Liens to repairs, renewals, replacements, substitutions, betterments, additions, extensions and improvements then or thereafter made on the property subject thereto;

(b) Financing of the Company's accounts receivable for electric service;

(c) Any extensions, renewals or replacements (or successive extensions, renewals or replacements), in whole or in part, of liens permitted by the foregoing clauses; and

(d) The pledge of any bonds or other securities at any time issued under any of the Secured Debt permitted by the above clauses.

In addition to the permitted issuances above, Secured Debt not otherwise so permitted may be issued in an amount that does not exceed 15% of Net Tangible Assets as defined below.

"Net Tangible Assets" means the total of all assets (including revaluations thereof as a result of commercial appraisals, price level restatement or otherwise) appearing on the Company's balance sheet, net of applicable reserves and deductions, but excluding goodwill, trade names, trademarks, patents,

unamortized debt discount and all other like intangible assets (which term shall not be construed to include such revaluations), less the aggregate of the Company's current liabilities appearing on such balance sheet. For purposes of this definition, the Company's balance sheet does not include assets and liabilities of its subsidiaries.

This restriction also does not apply to or prevent the creation or existence of leases made, or existing on property acquired, in the ordinary course of business.

3. You are hereby requested to authenticate \$75,000,000 aggregate principal amount of 5.625% Senior Notes, Series D, due 2032, executed by the Company and delivered to you concurrently with this Company Order and Officers' Certificate, in the manner provided by the Indenture.

4. You are hereby requested to hold the Notes as custodian for DTC in accordance with the Blanket Letter of Representations dated June 11, 2003, from the Company to DTC.

5. Concurrently with this Company Order and Officers' Certificate, an Opinion of Counsel under Sections 2.04 and 13.06 of the Indenture is being delivered to you.

6. The undersigned Henry W. Fayne and Thomas G. Berkemeyer, the President and Assistant Secretary, respectively, of the Company do hereby certify that:

(i) we have read the relevant portions of the Indenture, including without limitation the conditions precedent provided for therein relating to the action proposed to be taken by the Trustee as requested in this Company Order and Officers' Certificate, and the definitions in the Indenture relating thereto;

(ii) we have read the Board Resolutions of the Company and the Opinion of Counsel referred to above;

(iii) we have conferred with other officers of the Company, have examined such records of the Company and have made such other investigation as we deemed relevant for purposes of this certificate;

(iv) in our opinion, we have made such examination or investigation as is necessary to enable us to express an informed opinion as to whether or not such conditions have been complied with; and

(v) on the basis of the foregoing, we are of the opinion that all conditions precedent provided for in the Indenture relating to the action proposed to be taken by the Trustee as requested herein have been complied with.

Kindly acknowledge receipt of this Company Order and Officers' Certificate, including the documents listed herein, and confirm the arrangements set forth herein by signing and returning the copy of this document attached hereto.

Very truly yours,

KENTUCKY POWER COMPANY

By /s/ Henry W. Fayne
President

And: /s/ Thomas G. Berkemeyer
Assistant Secretary

Acknowledged by Trustee:

By: /s/ Susan Johnson
Authorized Signatory

KENTUCKY POWER COMPANY
Computation of Ratios of Earnings to Fixed Charges
(in thousands except ratio data)

	Year Ended December 31,				
	1999	2000	2001	2002	2003
Fixed Charges:					
Interest on First Mortgage Bonds	\$12,712	\$9,503	\$6,178	\$2,206	\$-
Interest on Other Long-term Debt	13,525	16,367	18,300	23,429	26,467
Interest on Short-term Debt	2,552	3,295	2,329	1,751	1,104
Miscellaneous Interest Charges	869	2,523	1,059	1,084	1,772
Estimated Interest Element in Lease Rentals	1,200	1,700	1,200	1,000	600
Total Fixed Charges	\$30,858	\$33,388	\$29,066	\$29,470	\$29,943
Earnings:					
Net Income Before Cumulative Effect of Accounting Change	\$25,430	\$20,763	\$21,565	\$20,567	\$33,464
Plus Federal Income Taxes	12,993	17,884	9,553	9,235	9,764
Plus State Income Taxes (Credits)	2,784	2,457	489	1,627	(89)
Plus Fixed Charges (as above)	30,858	33,388	29,066	29,470	29,943
Total Earnings	\$72,065	\$74,492	\$60,673	\$60,899	\$73,082
Ratio of Earnings to Fixed Charges	2.33	2.23	2.08	2.06	2.44

2003 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 Discussion and Analysis



AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

INDEX TO ANNUAL REPORTS

	<u>Page</u>
Glossary of Terms	i
Forward-Looking Information	iv
AEP Common Stock and Dividend Information	v
 American Electric Power Company, Inc. and Subsidiary Companies:	
Selected Consolidated Financial Data	A-1
Management's Financial Discussion and Analysis	A-2
Consolidated Financial Statements	A-46
Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries	A-51
Schedule of Consolidated Long-term Debt	A-52
Index to Notes to Consolidated Financial Statements	A-53
Independent Auditors' Report	A-133
Management's Responsibility	A-134
 AEP Generating Company:	
Selected Financial Data	B-1
Management's Narrative Financial Discussion and Analysis	B-2
Financial Statements	B-4
Statements of Capitalization	B-8
Index to Notes to Respective Financial Statements	B-9
Independent Auditors' Report	B-10
 AEP Texas Central Company and Subsidiary:	
Selected Consolidated Financial Data	C-1
Management's Financial Discussion and Analysis	C-2
Consolidated Financial Statements	C-10
Consolidated Statements of Capitalization	C-15
Schedule of Long-term Debt	C-16
Index to Notes to Respective Financial Statements	C-18
Independent Auditors' Report	C-19
 AEP Texas North Company:	
Selected Financial Data	D-1
Management's Narrative Financial Discussion and Analysis	D-2
Financial Statements	D-8
Statements of Capitalization	D-13
Schedule of Long-term Debt	D-14
Index to Notes to Respective Financial Statements	D-15
Independent Auditors' Report	D-16
 Appalachian Power Company and Subsidiaries:	
Selected Consolidated Financial Data	E-1
Management's Financial Discussion and Analysis	E-2
Consolidated Financial Statements	E-9
Consolidated Statements of Capitalization	E-14
Schedule of Long-term Debt	E-15
Index to Notes to Respective Financial Statements	E-17
Independent Auditors' Report	E-18
 Columbus Southern Power Company and Subsidiaries:	
Selected Consolidated Financial Data	F-1
Management's Narrative Financial Discussion and Analysis	F-2
Consolidated Financial Statements	F-8

Consolidated Statements of Capitalization	F-13
Schedule of Long-term Debt	F-14
Index to Notes to Respective Financial Statements	F-16
Independent Auditors' Report	F-17
Indiana Michigan Power Company and Subsidiaries:	
Selected Consolidated Financial Data	G-1
Management's Financial Discussion and Analysis	G-2
Consolidated Financial Statements	G-10
Consolidated Statements of Capitalization	G-15
Schedule of Long-term Debt	G-16
Index to Notes to Respective Financial Statements	G-18
Independent Auditors' Report	G-19
Kentucky Power Company:	
Selected Financial Data	H-1
Management's Narrative Financial Discussion and Analysis	H-2
Financial Statements	H-8
Statements of Capitalization	H-13
Schedule of Long-term Debt	H-14
Index to Notes to Respective Financial Statements	H-15
Independent Auditors' Report	H-16
Ohio Power Company Consolidated:	
Selected Consolidated Financial Data	I-1
Management's Financial Discussion and Analysis	I-2
Consolidated Financial Statements	I-12
Consolidated Statements of Capitalization	I-17
Schedule of Long-term Debt	I-18
Index to Notes to Respective Financial Statements	I-21
Independent Auditors' Report	I-22
Public Service Company of Oklahoma:	
Selected Financial Data	J-1
Management's Narrative Financial Discussion and Analysis	J-2
Financial Statements	J-7
Statements of Capitalization	J-12
Schedule of Long-term Debt	J-13
Index to Notes to Respective Financial Statements	J-15
Independent Auditors' Report	J-16
Southwestern Electric Power Company Consolidated:	
Selected Consolidated Financial Data	K-1
Management's Financial Discussion and Analysis	K-2
Consolidated Financial Statements	K-9
Consolidated Statements of Capitalization	K-14
Schedule of Long-term Debt	K-15
Index to Notes to Respective Financial Statements	K-17
Independent Auditors' Report	K-18
Notes to Respective Financial Statements	L-1
Registrants' Combined Management's Discussion and Analysis	M-1

GLOSSARY OF TERMS

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

<u>Term</u>	<u>Meaning</u>
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	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 AEPR.
AEPR	AEP Resources, 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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its 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 system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
ALJ	Administrative Law Judge.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities (the FERC overturned earlier approvals of this RTO in December 2001).
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APB 18	Accounting Principles Board Opinion Number 18: The Equity Method of Accounting for Investments in Common Stock.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The 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 Energy	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.

EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
ICR	Interchange Cost Reconstruction.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent System Operator.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, an AEP subsidiary.
LPSC	Louisiana Public Service Commission.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
MISO	Midwest Independent System Operator (an independent operator of transmission assets in the Midwest).
MLR	Member Load Ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool	AEP System's Money Pool.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
NOx Rule	A final rule issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operate.
NRC	Nuclear Regulatory Commission.
OCC	The Corporation Commission of the State of Oklahoma.
Ohio Act	The Ohio Electric Restructuring Act of 1999.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated Biphenyls.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP	Potentially Responsible Party.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	The Public Utilities Commission of Ohio.
PUCT	The Public Utility Commission of Texas.

PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Retail Electric Provider.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges, and non-derivative contracts held for trading purposes that were subject to mark-to-market accounting prior to January 1, 2003.
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.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, <u>Accounting for the Effects of Certain Types of Regulation</u> .
SFAS 101	Statement of Financial Accounting Standards No. 101, <u>Accounting for the Discontinuance of Application of Statement 71</u> .
SFAS 133	Statement of Financial Accounting Standards No. 133, <u>Accounting for Derivative Instruments and Hedging Activities</u> .
SFAS 143	Statement of Financial Accounting Standards No. 143, <u>Accounting for Asset Retirement Obligations</u> .
SFAS 149	Statement of Financial Accounting Standards No. 149, <u>Amendment of Statement 133 on Derivative Instruments and Hedging Activities</u> .
SFAS 150	Statement of Financial Accounting Standards No. 150, <u>Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity</u> .
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central Company, an AEP electric utility subsidiary.
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including TCC.
Superfund	The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
TVA	Tennessee Valley Authority.
U.K.	The United Kingdom.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WVPSC	Public Service Commission of West Virginia.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its 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.
- Available sources and costs of fuels.
- Availability of generating capacity and the performance of AEP's generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- New legislation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- AEP's ability to reduce its operation and maintenance costs.
- The success of disposing of investments that no longer match AEP's corporate profile.
- AEP's ability to sell assets at attractive prices and on other attractive terms.
- International and country-specific developments affecting foreign investments including the disposition of any current foreign investments.
- The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- AEP's ability to develop and execute on a point of view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt and preferred stock.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including the establishment of a regional transmission structure.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of AEP's pension plan.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and 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:

<u>Quarter Ended</u>	<u>High</u>	<u>Low</u>	<u>Quarter-end Closing Price</u>	<u>Dividend</u>
December 2003	\$30.59	\$26.69	\$30.51	\$0.35
September 2003	30.00	26.58	30.00	0.35
June 2003	31.51	22.56	29.83	0.35
March 2003	30.63	19.01	22.85	0.60
December 2002	\$30.55	\$15.10	\$27.33	\$0.60
September 2002	40.37	22.74	28.51	0.60
June 2002	48.80	39.00	40.02	0.60
March 2002	47.08	39.70	46.09	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2003, AEP had approximately 150,000 registered shareholders.

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

	2003	2002	2001	2000	1999
OPERATIONS STATEMENTS DATA			(in millions)		
Total Revenues	\$14,545	\$13,308	\$12,753	\$10,743	\$9,695
Operating Income	1,632	1,804	2,223	1,758	2,053
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	485	960	177	865
Discontinued Operations Income (Loss)	(605)	(654)	41	134	116
Extraordinary Losses	-	-	(48)	(44)	(9)
Cumulative Effect of Accounting Changes Gain (Loss)	193	(350)	18	-	-
Net Income (Loss)	110	(519)	971	267	972
BALANCE SHEET DATA			(in millions)		
Property, Plant and Equipment	\$36,033	\$34,127	\$32,993	\$31,472	\$30,476
Accumulated Depreciation and Amortization	14,004	13,539	12,655	12,398	11,895
Net Property, Plant and Equipment	\$22,029	\$20,588	\$20,338	\$19,074	\$18,581
Total Assets	\$36,744	\$35,890	\$40,432	\$47,703	\$36,297
Common Shareholders' Equity	7,874	7,064	8,229	8,054	8,673
Cumulative Preferred Stocks of Subsidiaries (a) (d)	137	145	156	161	182
Trust Preferred Securities (b)	-	321	321	334	335
Long-term Debt (a) (b)	14,101	10,190	9,409	8,980	9,471
Obligations Under Capital Leases (a)	182	228	451	614	610
COMMON STOCK DATA					
Earnings (Loss) per Common Share:					
Before Discontinued Operations, Extraordinary Items and Cumulative Effect	\$1.35	\$1.46	\$2.98	\$0.55	\$2.69
Discontinued Operations	(1.57)	(1.97)	0.13	0.42	0.36
Extraordinary Losses	-	-	(0.16)	(0.14)	(0.02)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06	-	-
Earnings (Loss) Per Share	\$0.29	\$(1.57)	\$3.01	\$0.83	\$3.03
Average Number of Shares Outstanding (in millions)	385	332	322	322	321
Market Price Range:					
High	\$31.51	\$48.80	\$51.20	\$48.94	\$48.19
Low	19.01	15.10	39.25	25.94	30.56
Year-end Market Price	30.51	27.33	43.53	46.50	32.13
Cash Dividends on Common (c)	\$1.65	\$2.40	\$2.40	\$2.40	\$2.40
Dividend Payout Ratio(c)	569.0%	(152.9)%	79.7%	289.2%	79.2%
Book Value per Share	\$19.93	\$20.85	\$25.54	\$25.01	\$26.96

(a) Including portion due within one year.

(b) See Note 17 of the Notes to Consolidated Financial Statements.

(c) Based on AEP historical dividend rate.

(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption which are classified in 2003 as Non-Current Liabilities.

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 service to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We have a vast portfolio of assets including:

- 38,000 megawatts of generating capacity, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in many of our market areas. Utility generating capacity of 4,500 megawatts located in Texas and approximately 280 megawatts of independent power generation located in Colorado and Florida are expected to be sold during 2004
- 39,000 miles of transmission lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 210,000 miles of distribution lines that deliver electricity to customers
- Substantial coal transportation assets (7,000 railcars, 1,800 barges, 37 towboats and two coal handling terminals with 20 million tons of annual capacity)
- 6,400 miles of gas pipelines in Louisiana and Texas with 127 Bcf of gas storage facilities. We have entered into an agreement to sell 2,000 miles of pipeline and plan to sell 9 Bcf of storage located in Louisiana related to our disposal of LIG
- 4,000 megawatts of generating capacity in the U.K., a market which we plan to exit by the end of 2004

BUSINESS STRATEGY

We will continue to concentrate our efforts on our domestic utilities. Our objectives are to be an economical, reliable and safe provider of energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low cost efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of energy by making significant investments into 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 and that provides a fair return for our shareholders through a stable stream of cash flows enabling us to pay competitive dividends.

We are addressing many challenges in our unregulated business. We have substantially reduced our trading activities that are not related to the sale of power from our owned-generation. We have written down the value of several investments to reflect deterioration in market conditions and sold or plan to sell assets that no longer fit our core business strategy. We have identified certain assets as "held-for-sale" and will move others to "held-for-sale" as we formalize and approve our plans for disposition. We will continue to operate HPL as we evaluate our future plans for this investment.

In summary our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate
- Maximize the value of our transmission assets and protect our revenue stream through membership in PJM
- Continue maintaining and improving distribution service quality
- Optimize generation assets by increasing availability and consequently increasing sales
- Complete the sales of our non-core assets

Regulation

- Focus on the regulatory process to maximize our earnings while providing fair and reasonable rates to our customers
- Complete the sale of our generation assets in Texas and recognize and recover the associated stranded costs in compliance with the law
- Complete the integration of the operation of our transmission system into PJM consistent with applicable regulatory requirements

Financial

- Operate only those unregulated investments that are consistent with our energy expertise and risk tolerance and that provide reasonable prospects for a fair return and moderate growth
- Continue to improve credit quality and maintain acceptable levels of liquidity
- Achieve moderate but steady earnings growth

2003 OVERVIEW

2003 was a year of transition for AEP. We repositioned ourselves to take advantage of, and maximize, the value of our utility assets. At the same time we took significant strides to exit non-core investments.

Our utility operations had a year of continued improvement resulting from strong wholesale results and our efforts to control and reduce operating costs. We reduced our losses from unregulated investments by reducing transitional trading losses and cutting related administrative expenses.

During 2003 we further stabilized our financial strength by:

- Issuing approximately \$1.1 billion in common stock
- Completing a cost reduction initiative which led to a \$392 million decline in operations and maintenance expenses during 2003 as compared to 2002. Savings of approximately \$139 million are attributable to our utility operations
- Minimizing future capital requirements associated with non-core assets
- Reducing our cash flow risk by limiting our trading activities to a level consistent with the scope of our generation fleet
- Stabilizing our credit ratings

We have redirected our business strategy by:

- Continuing to streamline our trading activities principally to support the sale of power from our core assets
- Actively pursuing the sale of all of our U.K. generation and our gas pipeline operations located in Louisiana; we expect each of these dispositions to be completed during 2004

OUTLOOK FOR 2004

We remain focused on the fundamental earning power of our utilities, and we are committed to strengthening our balance sheet. Our strategy for achieving these goals is well planned. We will:

- Continue to identify opportunities to further reduce both our operations and maintenance expenses and to efficiently manage our capital expenditures
- Seek rate changes that are fair and reasonable and that allow us to make the necessary operational and environmental improvements to our system
- Dispose of various unregulated assets to eliminate the negative earnings and cash consequences of these operations
- Use the proceeds from our dispositions to reduce debt and strengthen our capital structure
- Successfully operate certain unregulated investments such as our wind farms and our barge and river transport groups, which compliment our core capabilities
- Evaluate opportunities to hold and operate HPL under a revised business model that reduces commodity risk and earns reasonable returns for shareholders

Our objective is excellence in operations and results. There are, nevertheless, certain risks and challenges. We discuss these matters in detail in the Notes to Financial Statements and later in Management's Discussion and Analysis under the heading of Significant Factors. We will diligently resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

RESULTS OF OPERATIONS

In 2003, AEP's principal operating business segments and their major activities were:

- Utility Operations:
 - Domestic generation of electricity for sale to retail and wholesale customers
 - Domestic electricity transmission and distribution
- Investments-Gas Operations:*
- Gas pipeline and storage services
- Investments-UK Operations:**
 - International generation of electricity for sale to wholesale customers
 - Coal procurement and transportation to AEP plants and third parties
- Investments-Other:
 - Coal mining, bulk commodity barging operations and other energy supply related businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.

** UK Operations were classified as discontinued during 2003.

American Electric Power Company's consolidated Net Income (Loss) for the years ended December 31, 2003, 2002 and 2001 were as follows (Earnings and Average Shares Outstanding in millions):

	2003		2002		2001	
	<u>Earnings</u>	<u>EPS</u>	<u>Earnings</u>	<u>EPS</u>	<u>Earnings</u>	<u>EPS</u>
Utility Operations	\$1,218	\$3.17	\$1,154	\$3.47	\$941	\$2.92
Investments – Gas Operations	(290)	(.76)	(99)	(.29)	91	.28
Investments – UK Operations	-	-	-	-	-	-
Investments – Other	(277)	(.72)	(522)	(1.58)	-	-
All Other*	<u>(129)</u>	<u>(.34)</u>	<u>(48)</u>	<u>(.14)</u>	<u>(72)</u>	<u>(.22)</u>
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	1.35	485	1.46	960	2.98
Investments – Gas Operations	(91)	(.24)	8	.02	(4)	(.01)
Investments – UK Operations	(507)	(1.32)	(472)	(1.42)	(41)	(.13)
Investments – Other	<u>(7)</u>	<u>(.01)</u>	<u>(190)</u>	<u>(.57)</u>	<u>86</u>	<u>.27</u>
Discontinued Operations	(605)	(1.57)	(654)	(1.97)	41	.13
Extraordinary Loss	-	-	-	-	(48)	(.16)
Cumulative Effect of Accounting Changes	<u>193</u>	<u>.51</u>	<u>(350)</u>	<u>(1.06)</u>	<u>18</u>	<u>.06</u>
Total Net Income (Loss)	<u>\$110</u>	<u>\$.29</u>	<u>\$(519)</u>	<u>\$(1.57)</u>	<u>\$971</u>	<u>\$3.01</u>
Average Shares Outstanding		<u>385</u>		<u>332</u>		<u>322</u>

* All Other includes the parent company interest income and expense, as well as other non-allocated costs.

2003 Compared to 2002

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect in 2003 increased compared to 2002 due to increased wholesale earnings, lower impairment and other charges, and reduced operations and maintenance expenses. This increase was offset, in part, by milder weather and continuing weakness in the economy. Our Net Income for 2003 of \$110 million or \$.29 per share includes a loss, net of taxes, on discontinued operations of \$605 million and \$193 million of income, net of taxes, from the cumulative effect of changing our accounting for asset retirement obligations and for certain trading activities. Our Net Loss for 2002 of \$519 million or \$(1.57) per share includes a loss, net of taxes, on discontinued operations of \$654 million and a \$350 million, net of tax, charge for implementing a newly issued accounting pronouncement related to the impairment of goodwill.

During the fourth quarter of 2003 we concluded that the U.K. operations and LIG were not part of our core business and we began actively marketing each of these investments. The U.K. operations consist of our generation and trading operations that sell to wholesale customers. LIG's operations include 2,000 miles of intrastate gas pipelines and 9 Bcf of natural gas storage capacity. In addition, we recognized that poor market conditions also affected our merchant generation, other gas pipeline and storage assets, goodwill associated with these investments and various other assets. Based on market factors, as measured by a combination of indicative bids from unrelated interested buyers, independent appraisals, and estimates of cash flows, we recognized impairment losses of \$960 million, net of taxes.

Average shares outstanding increased to 385 million in 2003 from 332 million in 2002 due to a common stock issuance in March 2003. The additional average shares outstanding decreased our 2003 earnings per share by \$0.04.

2002 Compared to 2001

Our Net Loss was \$519 million or a loss of \$1.57 per share in 2002 which was a \$1.5 billion decline from 2001. Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect was negatively affected by plant availability, lower wholesale prices, reduced trading activity and write-offs to reduce the valuation of the under-performing assets. In the fourth quarter 2002, we recognized impairments on under-performing assets and recorded losses, net of taxes, of \$854 million. The losses in the fourth quarter 2002 were caused by the extended decline in domestic and international energy markets. In addition to the fourth quarter impairment losses, we had losses on discontinued operations of \$654 million including U.K. operations, SEEBOARD, Citipower and other investments and a loss for transitional goodwill impairment of \$350 million related to SEEBOARD and Citipower that resulted from the adoption of a newly issued accounting standard related to the impairment of goodwill.

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

Utility Operations

Summary of Selected Sales Data For Utility Operations For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Energy Summary	(in millions of KWH)		
Retail			
Residential	45,479	46,805	43,498
Commercial	37,104	36,487	35,589
Industrial	51,856	53,686	52,443
Miscellaneous	3,035	3,216	2,208
Total	<u>137,474</u>	<u>140,194</u>	<u>133,738</u>
Wholesale	<u>72,977</u>	<u>70,661</u>	<u>79,288</u>
 Weather Summary	 <u>2003</u>	 <u>2002</u>	 <u>2001</u>
	(in degree days)		
<u>Eastern Region</u>			
Actual – Heating	5,314	4,963	4,679
Normal – Heating*	5,182	5,177	5,232
 Actual – Cooling	757	1,252	1,021
Normal – Cooling*	975	1,013	997
 <u>Western Region</u>			
Actual – Heating	1,020	1,044	1,134
Normal – Heating*	1,062	1,034	1,060
 Actual – Cooling	2,220	2,369	2,377
Normal – Cooling*	2,217	2,224	2,233

*Normal Heating/Cooling represents the 30-year average of degree days.

2003 Compared to 2002

Earnings from Utility Operations increased \$64 million to \$1,218 million in 2003. Decreased operating expenses were partially offset by decreases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power decreased as follows:

- Residential demand decreased principally as a consequence of milder weather, and industrial demand was down due to the continued slow economic recovery. The combination of these factors reduced revenues net of related fuel and purchased power by approximately \$65 million.
- Reserves for final fuel factor decisions in Texas as well as other disallowances and associated rate reserves of \$102 million and lower regulatory deferrals for ECOM-based stranded costs of \$44 million reduced earnings. The provisions for stranded cost recovery in Texas recognize a regulatory asset or liability for the difference between the actual price received from the state-mandated auction of 15% of generation capacity and the earlier estimate of market price derived by a PUCT model.
- Fuel and purchased power costs increased by approximately \$40 million due in part to nuclear plant outages.
- During the fourth quarter of 2002, we exited trading activities that were not related to the sale of power from our owned-generation. The loss of these contributions from exiting the related trading positions reduced utility earnings by approximately \$70 million.

The decreases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales, including optimization activities, increased by approximately \$160 million primarily due to increased prices and plant availability.
- Transmission revenues increased by approximately \$45 million, due principally to increased wholesale power sales volumes.

Utility operating expenses decreased as follows:

- Maintenance and Other Operation expense decreased \$139 million due to continuing efforts to reduce costs, primarily labor and insurance, despite severe storm damage in the Midwest.
- Taxes Other Than Income Taxes decreased \$17 million primarily due to reduced gross receipts tax as a result of the sale of the Texas REPs.
- Depreciation and Amortization expense decreased \$18 million due to the change in our accounting for asset retirement obligations. The accounting change caused similar offsetting increases in Maintenance and Other Operation expenses.

2002 Compared to 2001

Earnings from Utility Operations increased \$213 million to \$1,154 million in 2002 due to an \$84 million gain on the sale of the Texas REPs and capital cost reductions of \$104 million, partially offset by a reduction in operating income.

Capital costs decreased due to reductions in short-term interest rates, lower outstanding balances of short-term debt and the refinancing of long-term debt at favorable interest rates. These reductions were partially offset by an increase in the amount of long-term debt outstanding.

Increased operating expenses were partially offset by increases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power increased as follows:

- ECOM-based Texas stranded cost deferrals increased \$262 million.
- Retail demand increased approximately \$180 million due to increased usage by residential customers. Eastern region cooling degree days were up 23% over 2001.

The increases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales net of related fuel and purchased power decreased \$126 million primarily due to lower plant availability, lower wholesale prices, the loss of certain municipal and co-op customers, and customers switching from FERC tariff-based to market-based rates.
- Trading operations, which decreased \$214 million as a result of our previously announced plan to exit trading activities that are not related to the sale of power from our owned-generation.

Utility operating expenses increased as follows:

- Maintenance and Other Operation expense increased \$102 million due to increased benefit costs of \$48 million, increased post September 11 insurance cost of \$35 million and increased nuclear maintenance and other expenses of \$19 million.
- Depreciation and Amortization expense increased \$46 million as a result of additional generation, transmission and distribution assets.
- Taxes Other Than Income Taxes increased \$70 million due to increased property and payroll taxes.

Investments – Gas Operations

2003 Compared to 2002

The loss from our Gas Operations of \$290 million increased \$191 million from 2002. This increase is primarily due to impairments recorded to reflect the reduction in the value of our gas assets. In the fourth quarter 2003, we recognized impairments and other related charges of \$228 million, net of tax, associated with HPL assets and goodwill based on market indicators supported by indicative bids received for LIG. These bids led us to conclude that purchasers were no longer willing to pay higher multiples for historic cash flows which included trading activities. Our previous operating strategy included higher risk tolerances associated with trading activities in order to achieve such operating results.

Partially offsetting the 2003 impairments, gas operations earnings have improved approximately \$68 million from 2002 due to a \$40 million decrease in losses associated with the options trading portfolio that we are no longer actively trading and exiting through a transition plan (our transition gas trading portfolio) and a \$28 million reduction in operating expenses. These earnings improvements were partially offset by \$15 million of losses due to unexpected late February 2003 sales to Entex, at fixed prices, when the Houston Ship Channel prices were at historic highs, a decrease in March deliveries due to unseasonably mild weather, and a decline in trading optimization of \$28 million due to lower risk tolerances and limits compared to the previous year.

2002 Compared to 2001

The loss from our Gas Operations of \$99 million increased \$190 million from 2001. The increase is due to significant trading losses in 2002 compared with strong trading results in 2001.

Investments – UK Operations

2003 Compared to 2002

The loss from our UK Operations of \$507 million for 2003 increased by \$35 million from 2002 and was due primarily to \$375 million, net of tax, of impairment and other related charges recorded during the fourth quarter. During 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. As a result, we devalued our UK investment based on bids received from interested unrelated buyers. The loss includes \$157 million of pre-tax losses associated with commitments for below market forward sales of power, which are beyond the date of the anticipated sale of these plants. We also experienced operating losses as a result of the deterioration of pretax trading margins of \$83 million associated with U.K. power and \$29 million associated with coal and freight.

2002 Compared to 2001

Our loss in 2002 from UK Operations of \$472 million increased by \$431 million from 2001. Our operations in the U.K. were dramatically expanded in December 2001 with the acquisition of two 2,000 MW generation stations. Goodwill and asset impairment charges of \$414 million, net of tax, contributed to our 2002 losses. The oversupply conditions throughout 2002 worsened in the fourth quarter after the British government's decision to subsidize British Energy, a financially troubled, dominant generator of power in the U.K. This intervention in the competitive market kept inefficient generation in the marketplace. The write-down of our two U.K. power plants was the result of our analyses that indicated U.K. power prices would not recover to levels that would permit us to carry the plants at their original purchase prices. In addition to unfavorable U.K. power and coal markets, higher than anticipated operating costs contributed to the loss in 2002.

Investments – Other

2003 Compared to 2002

The loss from our Other investments decreased by \$245 million to \$277 million in 2003. The decrease was primarily due to asset impairment charges of \$257 million, net of tax, compared to impairments of \$392 million, net of tax, recorded in 2002. 2003 impairments included losses of \$45 million, net of tax, for two of our independent generation facilities due to market conditions; \$168 million, net of tax, for the Dow facility due to the current market conditions and litigation; and coal mining asset impairments of \$44 million, net of tax, based on bids from unrelated parties. Additionally we incurred lower international development costs and reduced interest expenses during 2003.

2002 Compared to 2001

The loss from our Other investment operations of \$522 million resulted from \$392 million of asset impairment charges, net of tax. These write-downs in the fourth quarter of 2002 recognized the lower valuation in our investments in a utility in Brazil, AEP Communications and other under-performing assets. There were no such write-downs in 2001.

All Other

Our parent company's 2003 expenses increased \$81 million over 2002 primarily from higher interest costs due to increased debt at the parent level and reduced reliance on short-term borrowings as well as the recognition of estimated losses from certain litigation contingencies. Expenses in 2002 declined \$24 million from 2001 due to lower interest costs.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2003 we improved our financial condition as a consequence of the following actions and events:

- We issued approximately \$1.1 billion of new common equity
- We reduced our quarterly dividend in June 2003 to \$.35 per share which reduced our annualized cash outflows by approximately \$395 million
- We reduced short-term debt by \$2.8 billion, restructured our lines of credit into two \$750 million facilities, completed approximately \$1.3 billion of optional long-term debt redemptions, paid-off \$225 million of our Steelhead financing, and funded \$1.4 billion of debt maturities
- We limited our energy trading activity to levels necessary to optimize earnings from sales of our owned-generation
- Despite downgrades of certain debt ratings during the first quarter and continued uncertainty in the industry, we have maintained stable credit ratings across the AEP System

Capitalization

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Common Equity	35%	32 %	36%
Preferred Stock	1	1	1
Long-term Debt, including amounts due within one year	63	50	43
Short-term Debt	1	14	17
Minority Interest in Finance Subsidiary	<u>-</u>	<u>3</u>	<u>3</u>
Total Capitalization	<u>100%</u>	<u>100%</u>	<u>100%</u>

Our capital was affected by the following, during 2003:

- We recognized \$960 million of impairment losses related to our unregulated investments while reducing our ratio of debt to total capital
- We substantially reduced our short-term debt commitments, thereby reducing refinancing and cash flow risks
- We improved our percentage of common equity outstanding to total capitalization, in part through the issuance of approximately \$1.1 billion of new equity.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability due to volatility in wholesale power prices and the effects of credit rating downgrades. We are committed to preserving an adequate liquidity position.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position of approximately \$3.5 billion as illustrated in the table below:

	<u>Amount</u> (in millions)	<u>Maturity</u>
Commercial Paper Backup:		
Lines of Credit	\$ 750	May 2004
Lines of Credit	1,000	May 2005
Lines of Credit	750	May 2006
Euro Revolving Credit Facility	189	October 2004
Letter of Credit Facility	<u>200</u>	September 2006
Total	2,889	
Available Cash and Temporary Investments	<u>920*</u>	
Total Liquidity Sources	3,809	
Less: AEP Commercial Paper Outstanding	282**	
Letters of Credit Outstanding	<u>35</u>	
Net Available Liquidity	<u>\$3,492</u>	

* Available Cash and Temporary Investments of \$920 million and \$262 million in unavailable cash on hand make up the \$1.2 billion Cash and Cash Equivalents balance on our Consolidated Balance Sheet at December 31, 2003.

** Amount does not include JMG Funding LP (JMG) commercial paper outstanding in the amount of \$26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity to AEP.

Debt Covenants

Our revolving credit agreements 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, 2003, this percentage was 58.8%. Non-performance of these covenants may result in an event of default under these credit agreements. At December 31, 2003, we complied with the covenants contained in these credit agreements. In addition, the acceleration of the payment obligations of us, or 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 amounts outstanding thereunder payable.

Our commercial paper backup facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper.

Under an SEC order, AEP and its utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC due to its securitization bonds) of its capital. In addition, this order restricts AEP and 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.

Dividend Restrictions

Provisions within the Articles of Incorporation relating to the preferred stock of certain of our subsidiaries restrict the payment of cash dividends or other distributions on their common and preferred stock. PUHCA prohibits our subsidiaries from making loans or advances to the parent company, AEP. In addition, under PUHCA, AEP and its public utility subsidiaries can only pay dividends out of retained or current earnings.

Credit Ratings

We also manage our liquidity by continuing to maintain investment grade credit ratings and a stable credit outlook and are taking steps to improve our credit quality, including plans during 2004 to further reduce our outstanding debt through the use of proceeds from the planned dispositions. If we receive a downgrade in our credit ratings by these agencies, our borrowing costs could increase. The rating agencies currently have AEP and our rated subsidiaries on stable outlook. Current ratings for AEP are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
AEP Short-Term Debt	P-3	A-2	F-2
AEP Senior Unsecured Debt	Baa3	BBB	BBB

Cash Flow

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

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	<u>\$1,199</u>	<u>\$194</u>	<u>\$232</u>
Net Cash Flows From Operating Activities	2,308	2,067	2,818
Net Cash Flows Used For Investing Activities	(1,888)	(378)	(3,292)
Net Cash Flows (Used For) From Financing Activities	(437)	(681)	437
Effect of Exchange Rate Changes on Cash	-	(3)	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	<u>(17)</u>	<u>1,005</u>	<u>(38)</u>
Cash and Cash Equivalents at End of Period	<u><u>\$1,182</u></u>	<u><u>\$1,199</u></u>	<u><u>\$194</u></u>

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings provide working capital and 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 non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling \$2.9 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, preferred stock or long-term debt and sale-leaseback or leasing agreements. Money pool and external borrowings may not exceed SEC authorized limits.

Operating Activities

	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
Net Income (Loss)	\$110	\$(519)	\$971
Plus: Discontinued Operations	<u>605</u>	<u>654</u>	<u>(41)</u>
Income from Continuing Operations	715	135	930
Noncash Items Included in Earnings	1,798	2,734	976
Changes in Assets and Liabilities	<u>(205)</u>	<u>(802)</u>	<u>912</u>
Net Cash Flows From Operating Activities	<u>\$2,308</u>	<u>\$2,067</u>	<u>\$2,818</u>

2003 Operating Cash Flow

Our cash flows from operating activities were \$2.3 billion for 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 is a current period impact for a net \$122 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. 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. The current period activity in these asset and liability accounts relates to a number of items; the most significant are presented below:

- The wholesale capacity auction true-up (ECOM) resulted in stranded cost deferrals of \$218 million, which are not recoverable in cash until the conclusion of our Texas true-up proceeding. These proceedings are not expected to be finalized earlier than April 2005.
- Net changes in accounts receivable and accounts payable of \$269 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 in earlier periods.
- Increases in inventory levels of \$71 million resulting primarily from higher procurement prices.
- Reserves for disallowed fuel costs, principally related to Texas, which will be a component of our 2004 final Texas true-up order of the PUCT.

2002 Operating Cash Flow

During 2002, our cash flows from operating activities were \$2.1 billion. Income from continuing operations was \$135 million during the period. Income from continuing operations for 2002 included noncash items of \$1.4 billion for depreciation, amortization, and deferred taxes, \$350 million related to the cumulative effect of an accounting change, and \$639 million for impairment losses. There was a current period impact for a net \$275 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts related to the wholesale capacity auction true-up asset (ECOM) of \$262 million, deposits associated with risk management activities of \$136 million, and seasonal increases in our fuel inventories.

2001 Operating Cash Flow

Our cash flows from operating activities were \$2.8 billion for 2001. Income from continuing operations was \$930 million during the period. Income from continuing operations for 2001 included noncash items of \$1.5 billion for depreciation, amortization, and deferred taxes, and \$18 million related to the cumulative effect of an accounting change. There was a current period impact for a net \$294 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts was primarily attributable to increased levels of trading activities as compared to 2002 and 2003. During the fourth quarter of 2002 we exited trading that was not related to the sale of power from our owned-generation.

Investing Activities

	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
Construction Expenditures	\$(1,358)	\$(1,685)	\$(1,646)
Business Acquisitions/Sales Proceeds, net	82	1,263	(621)
Other	(612)	44	(1,025)
Net Cash Flows Used for Investing Activities	<u>\$(1,888)</u>	<u>\$(378)</u>	<u>\$(3,292)</u>

Our cash flows used for investing activities increased \$1.5 billion in 2003 from \$378 million during the prior year. This increase was due to additional sales proceeds in 2002 related to SEEBOARD, CitiPower, and the Texas REPs as well as increased investments in our U.K. operations during 2003. These increases were partially offset by a reduction of our capital expenditures in 2003 as compared to 2002.

In 2002, our cash flows used for investing activities decreased \$2.9 billion from 2001. This decrease resulted from the HPL and UK acquisitions during 2001 as well as the net increase in proceeds received from asset sales during 2002.

We forecast \$5.8 billion of construction expenditures for 2004-2006.

Financing Activities

	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
Issuances of Equity Securities (common stock/equity units)	\$1,142	\$990	\$11
Issuances/Retirements of Debt, net	(727)	(868)	460
Retirement of Preferred Stock	(9)	(10)	(5)
Issuance/Retirement of Minority Interest	(225)	-	744
Dividends	(618)	(793)	(773)
Net Cash Flows (Used for) From Financing Activities	<u>\$(437)</u>	<u>\$(681)</u>	<u>\$437</u>

Our cash flows used for financing activities decreased \$244 million in 2003 from \$681 million during the prior year. This decrease was due to additional proceeds from the issuance of common stock and the reduction of our common stock dividend in 2003.

In 2002 we used \$681 million for financing activities compared to \$437 million provided by the same activities in 2001. The increase in cash used pertained primarily to the debt retirements that occurred in 2002.

The following financing activities occurred during 2003 and 2002:

Common Stock and Equity Units:

- In March 2003, we issued 56 million shares of common stock at \$20.95 per share through an equity offering and received net proceeds of \$1.1 billion (net of issuance costs of \$36 million). We used the proceeds to pay down both short-term and long-term debt with the balance being held in cash.

- In June 2002, we issued 16 million shares of common stock at \$40.90 per share and 6.9 million equity units at \$50 per unit and received combined net proceeds of \$979 million. We used the proceeds to pay down short-term debt and establish a cash liquidity reserve fund.

Debt:

- 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 non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling \$2.9 billion to support our commercial paper program. At December 31, 2003, we had \$282 million outstanding in short-term borrowings supported by these credit facilities. In addition, JMG has commercial paper outstanding in the amount of \$26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity.
- In February 2003, we issued over \$2 billion of senior notes through our Ohio and Texas subsidiaries. The proceeds were used to repay the bank facility that was due to mature in April 2003, retire short-term debt and for other general corporate purposes. During the remainder of the year, our subsidiaries issued an additional \$2.3 billion in senior notes and refinanced approximately \$465 million in pollution control revenue bonds. The proceeds of these issuances were used to term-out short-term debt, fund long-term debt maturities and fund optional redemptions.
- In March 2003, AEP issued a \$500 million senior unsecured note. The proceeds of this issuance were used to pay-down \$225 million of the Steelhead financing and to prefund a portion of the AEP Resources bond that matured in December 2003.
- In May 2003, a third party exercised its option to call our \$250 million of 5.50% putable callable notes, issued in May 2001, for purchase and remarketing. On May 15, 2003, AEP issued \$300 million of 5.25% senior notes due 2015, a portion of which was an exchange for the \$250 million putable callable notes due in 2003 that were outstanding at that time.
- AEP Credit extended its sale of receivables agreement from its May 28, 2003 expiration to July 25, 2003, when the agreement was renewed for an additional 364 days. The sale of receivables agreement, which expires on July 23, 2004, provides commitments of \$600 million to purchase receivables from AEP Credit. At December 31, 2003, \$385 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.
- In September 2003, we closed on a \$200 million revolving loan and letter of credit facility. The facility is available for the issuance of letters of credit and for general corporate purposes. The facility will expire in September 2006.

Minority Interest and Off-balance Sheet Arrangements

We enter into minority interest and 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 minority interest and off-balance sheet arrangements:

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 was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and \$321.4 million of AEP Energy Services Gas Holding Company

(AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into our common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with \$2 million cash and a subscription agreement that represents an unconditional obligation to fund \$83 million from SubOne for a managing member interest and \$750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. SubOne is the managing member of Caddis. As a result SubOne and all of its subsidiaries, including Caddis, HPL and LIG, are included in our Consolidated financial statements.

Steelhead is an unconsolidated special purpose entity and had an original capital structure of \$750 million (currently approximately \$525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The \$525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the planned sale of LIG will be used to reduce the outstanding balance of the loan from Caddis.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary (\$759 million at December 31, 2002 and \$533 million at June 30, 2003). As a result, a \$527 million note payable to Caddis is part of our Long-Term Debt at December 31, 2003. Application of FIN 46 is prospective and we, therefore, did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

On May 9, 2003, we reduced the outstanding balance of our note payable to Caddis by \$225 million. Caddis used these proceeds to reduce the preferred interest in Caddis that was held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of our outstanding debt in excess of \$50 million would be an event of default under the credit agreement.

SubOne has deposited \$422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

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, 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 does not consolidate these entities in accordance with GAAP. We continue 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 extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of \$600 million to purchase receivables from AEP Credit. At December 31, 2003, \$385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold

and this interest is pledged as collateral for the collection of the 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 \$1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

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. 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 with the future payment obligations included in the annual lease footnote. 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, 2003, the maximum potential loss was approximately \$31.5 million (\$20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has 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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$1,779	\$3,460	\$1,711	\$7,151	\$14,101
Short-term Debt	326	-	-	-	326
Preferred Stock Subject to Mandatory Redemption	-	-	21	55	76
Capital Lease Obligations	63	77	49	31	220
Unconditional Purchase Obligations (a)	1,720	2,132	1,101	1,785	6,738
Noncancellable Operating Leases	291	492	441	2,331	3,555
Total	<u>\$4,179</u>	<u>\$6,161</u>	<u>\$3,323</u>	<u>\$11,353</u>	<u>\$25,016</u>

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under “Minority Interest and Off-Balance Sheet Arrangements” above, include contractual cash obligations reported in the above table. The lease of Rockport Unit 2 and Railcars are reported in Noncancellable Operating Leases. The Minority Interest in Finance Subsidiary is reported in Long-term Debt.

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. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

<u>Other Commercial Commitments</u>	Amount of Commitment Expiration Per Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Standby Letters of Credit (a)	\$175	\$43	\$-	\$9	\$227
Guarantees of the Performance of Outside Parties (b)	-	18	1	134	153
Guarantees of our Performance	1,083	107	-	8	1,198
Transmission Facilities for Third Parties (c)	99	110	54	-	263
Other Commercial Commitments (d)	14	14	-	-	28
Total Commercial Commitments	<u>\$1,371</u>	<u>\$292</u>	<u>\$55</u>	<u>\$151</u>	<u>\$1,869</u>

(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 the ordinary course of business. The maximum future payments of these letters of credit are \$227 million with maturities ranging from January 2004 to January 2011. As the parent of all of these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) These amounts are the balances drawn, not the maximum guarantee disclosed in Note 8.

- (c) 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.
- (d) OPCo has entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, OPCo has the option to run the plant until December 31, 2005, taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at \$1.2 million per month. For the remainder of the 30-year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity.

Expenditures for domestic electric utility construction are estimated to be \$5.8 billion for the next three years. Approximately 80% of those construction expenditures is expected to be financed by internally generated funds.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated 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 with debt financing up to \$494 million and equity up to \$31 million from investors with no relationship to AEP or any of AEP's subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded \$496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. 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 an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease 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 \$396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the \$396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled \$496 million, and total costs for the completed Facility are currently expected to be approximately \$525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately \$18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to \$396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected \$396 million of the \$496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is \$396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of \$496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to 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 non-conforming.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately \$17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by 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 \$258 million pre-tax impairment in December 2003 on the CWIP.

SIGNIFICANT FACTORS

Possible Divestitures

We are firmly committed to continually evaluating the need to reallocate resources to areas that effectively match our investments with our business strategy, providing the greatest potential for financial returns. We are committed to disposing of investments that no longer meet these goals.

We are seeking to divest significant components of our non-regulated assets, including certain domestic and international unregulated generation, part of our gas pipeline and storage business, a coal business, independent power producers (IPPs) and a communications business. In June 2003, we began actively seeking buyers for 4,497 megawatts of unregulated generating capacity in Texas. The value received from this disposition will also be used to calculate our stranded costs in Texas (see Note 6). We are currently evaluating bids received during the fourth quarter of 2003 and are in negotiations to sell these assets.

During the second quarter of 2003, we also hired an advisor to evaluate our coal business, which has resulted in the receipt of non-binding bids. We are currently negotiating the anticipated sale of certain assets from this business. In the fourth quarter of 2003, in connection with the evaluation of this business, we recorded a \$66.6 million pre-tax charge related to asset impairments, remediation accruals and other exit costs (see Note 10).

During the third quarter of 2003, management hired advisors to review business options regarding various investment components of our Gas Operations. We distributed an initial offering memorandum and request for proposal on the sale of our Louisiana Intrastate Gas and Jefferson Island Storage Facility operations during the fourth quarter of 2003. We are currently evaluating the proposals that we received. We are evaluating the merits of retaining our interest in Houston Pipe Line, which is part of Gas Operations. In connection with our review of the Gas Operations, we recorded \$133.9 million in pre-tax charges related to LIG and \$315 million in pre-tax charges related to HPL (see Note 10). We signed a sale agreement for the pipeline portion of LIG in the first quarter of 2004 and we expect the sale to close shortly with an immaterial impact on 2004 results of operations.

During the third quarter of 2003, we initiated an effort to sell four domestic IPP investments. Based on studies using current market assumptions, we believe that two of the facilities had declines in fair value that are other than temporary in nature. As a consequence, we recorded an impairment of \$70 million pre-tax (\$45.5 million net of tax) in the third quarter of 2003 (see Note 10). During the fourth quarter of 2003, we distributed an information memorandum related to the possible sale of our interest in these IPPs. We have received and are reviewing final bids and anticipate a sale of the four domestic IPP investments in 2004.

During the fourth quarter of 2003, we engaged an advisor for the disposition of our U.K. business and are planning to dispose of these assets in 2004. In connection with the evaluation of this business, we recorded a pre-tax charge of \$577.4 million during the fourth quarter of 2003 based on indications of value received from potential buyers (see Note 10).

Management continues to have periodic discussions with various parties on business alternatives for certain of our other non-core investments.

The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal. We may realize losses from operations or upon disposition of these assets that, in the aggregate, could have a material impact on our results of operations, cash flows and financial condition.

Corporate Separation

In Texas, we are in the process of divesting our TCC generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which we expect to be finalized in 2004, we will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of our states requires RTO participation.

In May 2002, we announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, our subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately \$98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately \$13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at \$24 million for AEP's share of the entire PJM integration project). AEP also has \$28 million, at December 31, 2003, of deferred RTO formation/integration costs for which we plan to seek recovery in the future. See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate our SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at FERC for recognition as an RTO. In February 2004, FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on our transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess 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.

Our net periodic pension expense was an income item for all pension plans approximating \$3 million and \$44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. 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 2003, of approximately 10.0%. We anticipate that the investment managers we employ for the pension fund will continue to generate long-term returns of at least 8.75%.

The expected long-term rate of return on the Qualified Plan's 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:

	<u>2003 Actual Asset Allocation</u>	<u>2004 Target Asset Allocation (in percentage)</u>	<u>Assumed/Expected Long-term Rate of Return</u>
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	<u>100</u>	<u>100</u>	
Overall Expected Return (weighted average)			<u>8.75</u>

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. We believe that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them 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, 2003, we had cumulative losses of approximately \$325 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 discount rate that we utilize for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, we estimate that the pension expense for all pension plans will approximate \$41 million, \$78 million and \$103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately \$18 million (income of \$3 million would have become \$15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately \$0.5 million.

The value of the Qualified Plans' assets has increased from \$2.795 billion at December 31, 2002 to \$3.180 billion at December 31, 2003. The Qualified Plans paid out \$292 million in benefits to plan participants during 2003 (the nonqualified plans paid out \$7 million in benefits). Our plans remain in an underfunded position (plan assets are less than projected benefit obligations) of \$508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded a charge to Other Comprehensive Income (OCI) of \$585 million in 2002, and recorded a Deferred Income Tax Asset of \$315 million, offset by a Minimum Pension Liability of \$662 million and a reduction to prepaid costs and adjustment for unrecognized costs of \$238 million. In 2003, the income recorded in OCI was \$154 million, and the reduction in the Deferred Income Tax Asset was \$76 million, offset by a reduction in Minimum Pension Liability of \$234 million and a reduction to adjustment for unrecognized costs of \$4 million. The charge to OCI does not affect earnings or cash flow. Due to the current underfunded status of the Qualified Plans, we expect to make cash contributions to the pension plans of approximately \$41 million in 2004.

Certain of the defined benefit 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, 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 substantial compliance with the applicable requirements of such laws.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. Our share of the cost of repair for this outage was approximately \$6 million. We had commitments to provide power to customers during the outage. Therefore, we were subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of the Federal EPA Complaint and Notice of Violation within “Significant Factors – Environmental Matters.”

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron’s bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron’s bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 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. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL’s exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks 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 banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA’s breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. 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 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 will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately \$93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of \$53 million (\$34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. 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.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately \$34 million. In April 2003, we filed a lawsuit 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 and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately \$68 million. We are claiming that BOM owes us at least \$45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding results from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries. AEP and Williams settled the dispute with AEP paying \$90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter had an immaterial impact on results of operations and financial condition. See Note 7 for further discussion.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately \$22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement with AEP paying approximately \$11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigations

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 has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC seeking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges 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 seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, we recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

Shareholders' Litigation

In 2002, lawsuits alleging securities law violations, a breach of fiduciary duty for failure to establish and maintain adequate internal controls and violations of the Employee Retirement Income Security Act were filed against us, certain executives, members of the Board of Directors and certain investment banking firms. We intend to vigorously defend against these actions. See Note 7 for further discussion.

California Lawsuit

In 2002, the Lieutenant Governor of California filed a lawsuit in 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. See Note 7 for further discussion.

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. Shortly thereafter, a similar action was filed in the same court against eighteen companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases are in the initial pleading stage. Management believes that the cases are without merit and intends to vigorously defend against them.

TEM Litigation

See discussion of TEM litigation within the "Financial Condition – Other" section of Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT alleging 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 alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over \$500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against us are without merit. We intend to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a \$319 million reduction in AEP's Net Income for 2000. We filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Snohomish Settlement

In February 2003, AEP and the Public Utility District No. 1 of Snohomish County, Washington (Snohomish) agreed to terminate their long-term contract signed in January 2001. Snohomish also agreed to withdraw its complaint before the FERC regarding this contract and paid \$59 million to us. The settlement amount was less than the amount receivable that, in the ordinary course of business, we recorded using MTM accounting. As a result, we incurred a \$10 million pre-tax loss.

Other Litigation

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

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 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 recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO₂), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
- New Clean Water Act rules 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 emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, we strive to go beyond compliance in an effort to be good environmental stewards. For example, we invest in research, through groups like the Electric

Power Research Institute, to develop, implement and demonstrate new emission control technologies. We plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. We have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. We invested over \$2 billion, from 1990 through 2003, to equip many of our facilities with pollution control technologies. We will continue to make investments to improve the air emissions from our generating stations because this is the most cost-effective generation source for our customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as “national ambient air quality standards” (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state’s SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states’ SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NO_x Rule in 1997, which affected 22 eastern states (including states in which AEP operates) and the District of Columbia. The NO_x Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NO_x emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NO_x Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NO_x Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NO_x Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NO_x Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NO_x emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

We are installing a variety of emission control technologies to improve NO_x emissions standards and to comply with applicable state and federal NO_x requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO₂ and particulate matter emissions in all states, and that control NO_x emissions in certain states. Our generating plants comply with applicable SIP limits for SO₂, NO_x and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO₂, NO_x, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO₂ emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO₂ emissions of 8.9 million tons per year. The Federal EPA administers its SO₂ program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO₂ that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NO_x emissions through the use of available combustion controls. Units must meet NO_x emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO₂, NO_x, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO₂ and NO_x emissions as precursors to the formation of fine particulate matter. NO_x emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO_x and SO₂ from our generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NO_x, SO₂, and mercury emissions from electric generating plants. We support enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require us to substantially reduce SO₂, NO_x and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO₂, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO₂ and NO_x emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NO_x and SO₂ emissions from coal-fired electric utility units. SO₂ and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO₂ emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO_x emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO₂ and NO_x trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO₂ (scrubbers) and NO_x (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO₂ and NO_x reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO₂ and NO_x requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO₂, NO_x and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require us to make significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

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, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Estimated Investments for NO_x Compliance

We estimate that we will make future investments of approximately \$600 million to comply with the Federal EPA's NO_x Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NO_x-related requirements. Approximately \$500 million of these investments are reflected in our estimated construction expenditures for 2004 – 2006. As of December 31, 2003, we have invested approximately \$1.1 billion to comply with various NO_x requirements.

Estimated Investments for SO₂ Compliance

We are complying with Title IV SO₂ requirements by installing scrubbers, other controls and fuel switching at certain generating units. We also use SO₂ allowances that we:

- Receive in the annual allowance allocation by the Federal EPA,
- Obtain through participation in the annual allowance auction,
- Purchase in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO₂ allowance allocations, a diminishing SO₂ allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of

additional scrubbers over the next 4 years to comply with our Title IV SO₂ obligations. In total we estimate these additional capital costs to be approximately \$1.2 billion. Of this total, we estimate that \$900 million will be expended during 2004-2006 and this amount is included in our total estimated construction expenditures for 2004 – 2006.

Estimated Investments to Comply with Future Reduction Requirements

Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO₂, NO_x and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately \$1.7 billion by 2010, the end of the first phase for each proposed rule. We also estimate that we would incur increases in variable operation and maintenance expenses of \$150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents. We estimate that we will invest \$200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

If the Federal EPA's preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would also have implementation costs that could be significant. We cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that AEP operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which we are not able to estimate, would be incremental to other cost estimates that we have discussed above.

Beyond 2010, we expect to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. We cannot estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

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 Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs 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 relate to costs that were incurred at our generating units over a 20-year period.

We are unable to estimate the loss or range of loss related to the contingent liability 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, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would 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.

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 disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. We are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, subsidiaries of AEP are named by the Federal EPA as a PRP for five sites. There are six 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 six sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. 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. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

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.

Global Climate Change

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 CO₂, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO₂ and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the Clean Air Act to regulate CO₂ or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We do not support the Kyoto Protocol but have been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which we are obligated to reduce or offset 18 million tons of CO₂ emissions during 2003-2006.

We acquired 4,000 MW of coal-fired generation in the United Kingdom in December 2001. These assets may have future CO₂ emission control obligations beginning in 2005. We plan to dispose of our investment in this generation during 2004.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected \$316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited \$117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted \$199 million to the DOE. TCC has collected and remitted to the DOE, \$56 million for the future disposal of SNF since STP began operation in the late 1980s. 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. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with 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, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of unaffiliated 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 the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M 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 August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from \$821 million to \$1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was \$720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC's share of decommissioning cost to be \$289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2003, the total decommissioning trust fund for TCC's share of STP was \$125 million which includes earnings on the trust investments. Estimates from the decommissioning studies 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 and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. 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.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

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 which 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 results of operations, cash flows and possibly financial condition.

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting

principles generally accepted in the United States of America, including amounts related to legal matters and contingencies. Actual results can differ significantly from those estimates under different assumptions and conditions.

We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

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. 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 its passage to customers through regulated revenues in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not yet been made.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

We recognize revenues on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. That is, we recognize and record revenues when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities

We recognize revenues from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and are required to be accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in 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 mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into 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.

After January 1, 2003, we use mark-to-market 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. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions we recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When we settle mark-to-market derivative contracts and realize gains and losses, we reverse previously recorded unrealized gains and losses from mark-to-market valuations.

We designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). We report changes in the fair value of these instruments on our balance sheet. We do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. We also recognize any changes in the fair value of the hedging instrument that are not offset by changes in the fair value of the hedged item immediately in earnings.

We measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market 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 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. We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. 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.

Pension Benefits

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in Significant Factors section of Management's Financial Discussion and Analysis.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company (\$77.8 million) and JMG (\$469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated Cadis Partners, LLC and the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Minority Interest in Finance Subsidiary (\$533 million) and Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries (\$321 million), respectively. As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 to the consolidated financial statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

The sale of electric power in our service territories 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 our facilities and the terms of power contracts into which we enter. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and may impact cash flows and financial condition.

Non-Core Investments

Additional market deterioration associated with our non-core wholesale investments (all operations outside our traditional domestic regulated utility operations), including our U.K. operations, merchant generation facilities, and certain gas storage and pipeline assets, could have an adverse impact on future results of operations and cash flows. Further changes in external market conditions could lead to additional write-offs and further divestitures of our wholesale investments, including, but not limited to, the U.K. operations, merchant generation facilities, and our gas

storage and pipeline operations. See Note 10 for additional information regarding assets and investments currently recorded as held for sale.

Investments Limitations

Our investment, including guarantees of debt, in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits us to issuing and selling securities in an amount up to 100% of our average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2003, our investment in EWGs and FUCOs was \$1.7 billion, including guarantees of debt, compared to our limit of \$2.1 billion.

SEC Rule 58, under the general rules and regulations of the PUHCA, permits us to invest up to 15% of consolidated capitalization (such amount was \$3.4 billion at December 31, 2003) in energy-related companies, including marketing and/or risk management activities in electricity, gas and other energy commodities. As of December 31, 2003 AEP has invested \$2.8 billion in these energy-related companies.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity and natural gas, we have certain market risks inherent in our business activities. 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.

We have established policies and procedures which 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, Chief Credit Officer, V.P. Market Risk Oversight, and 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. The following tables provide information on our risk management activities.

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

This table provides detail on changes in our mark-to-market (MTM) net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets (Liabilities) Year Ended December 31, 2003

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
	(in millions)			
Beginning Balance December 31, 2002	\$360	\$(155)	\$ 45	\$250
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(107)	175	(9)	59
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	4	4
Net Option Premiums Paid/(Received) (c)	-	23	(14)	9
Change in Fair Value Due to Valuation Methodology Changes	-	1	-	1
Effect of EITF 98-10 Rescission (d)	(19)	1	(14)	(32)
Changes in Fair Value of Risk Management Contracts (e)	43	(40)	(134)	(131)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9	-	-	9
UK Generation Hedges (g)	<u>-</u>	<u>-</u>	<u>(124)</u>	<u>(124)</u>
Total MTM Risk Management Contract Net Assets (Liabilities), excluding Cash Flow Hedges	<u>\$286</u>	<u>\$5</u>	<u>\$(246)</u>	45
Net Cash Flow Hedge Contracts (h)				(134)
Net Risk Management Liabilities Held for Sale (i)				<u>383</u>
Ending Balance December 31, 2003				<u><u>\$294</u></u>

- (a) “(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 and entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value at inception of long-term contracts entered into with customers during 2003. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c) “Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect.”
- (e) “Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (f) “Change in Fair Value of Risk Management Contracts 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.
- (g) “UK Generation Hedges” represent amounts previously classified as hedges of forecasted U.K. power sales relating to the fourth quarter of 2004 and beyond. Given the expected disposition of our U.K. generation in 2004, the forecasted sales are no longer probable of occurring. Therefore, these amounts have been reclassified from hedge accounting to mark-to-market accounting.
- (h) “Net Cash Flow Hedge Contracts” (pre-tax) are discussed in detail within the following pages.
- (i) See Note 10 for discussion on Assets Held for Sale.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of December 31, 2003

	<u>Utility Operations</u>	<u>Investments Gas Operations</u>	<u>Investments UK Operations</u>	<u>Consolidated</u>
		(in millions)		
Current Assets	\$323	\$417	\$560	\$1,300
Non Current Assets	279	215	274	768
Total Assets	<u>\$602</u>	<u>\$632</u>	<u>\$834</u>	<u>\$ 2,068</u>
Current Liabilities	\$(216)	\$(403)	\$(646)	\$(1,265)
Non Current Liabilities	(100)	(224)	(434)	(758)
Total Liabilities	<u>\$(316)</u>	<u>\$(627)</u>	<u>\$(1,080)</u>	<u>\$(2,023)</u>
Total Net Assets (Liabilities), excluding Cash Flow Hedges	<u>\$286</u>	<u>\$5</u>	<u>\$(246)</u>	<u>\$45</u>

**Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets**
As of December 31, 2003

	<u>Risk Management Contracts*</u>	<u>Cash Flow Hedges</u>	<u>Assets Held for Sale</u>	<u>Consolidated</u>
		(in millions)		
Current Assets	\$1,300	\$26	\$(560)	\$766
Non Current Assets	768	-	(274)	494
Total Assets	<u>\$2,068</u>	<u>\$26</u>	<u>\$(834)</u>	<u>\$1,260</u>
Current Liabilities	\$(1,265)	\$(148)	\$782	\$(631)
Non Current Liabilities	(758)	(12)	435	(335)
Total Liabilities	<u>\$(2,023)</u>	<u>\$(160)</u>	<u>\$1,217</u>	<u>\$(966)</u>
Total Net Assets (Liabilities)	<u>\$45</u>	<u>\$(134)</u>	<u>\$383</u>	<u>\$294</u>

* Excluding Cash Flow Hedges.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information.

- The source of 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, giving 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, 2003**

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008 (c)</u>	<u>Total (d)</u>
	(in millions)						
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	\$44	\$(4)	\$(1)	\$-	\$-	\$-	\$39
Prices Provided by Other External Sources – OTC Broker Quotes (a)	78	38	29	13	6	-	164
Prices Based on Models and Other Valuation Methods (b)	<u>(15)</u>	<u>7</u>	<u>15</u>	<u>19</u>	<u>16</u>	<u>41</u>	<u>83</u>
Total	<u>\$107</u>	<u>\$41</u>	<u>\$43</u>	<u>\$32</u>	<u>\$22</u>	<u>\$41</u>	<u>\$286</u>
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	\$49	\$14	\$(1)	\$-	\$-	\$-	\$62
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(27)	-	-	-	-	-	(27)
Prices Based on Models and Other Valuation Methods (b)	<u>(8)</u>	<u>(7)</u>	<u>(6)</u>	<u>(1)</u>	<u>(3)</u>	<u>(5)</u>	<u>(30)</u>
Total	<u>\$14</u>	<u>\$7</u>	<u>\$(7)</u>	<u>\$(1)</u>	<u>\$(3)</u>	<u>\$(5)</u>	<u>\$5</u>
Investments - UK Operations:							
Prices Actively Quoted – Exchange Traded Contracts	\$-	\$-	\$-	\$-	\$-	\$-	\$-
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(60)	(101)	(46)	-	-	-	(207)
Prices Based on Models and Other Valuation Methods (b)	<u>(26)</u>	<u>(9)</u>	<u>(2)</u>	<u>(2)</u>	<u>-</u>	<u>-</u>	<u>(39)</u>
Total	<u>\$(86)</u>	<u>\$(110)</u>	<u>\$(48)</u>	<u>\$(2)</u>	<u>\$-</u>	<u>\$-</u>	<u>\$(246)</u>
Consolidated:							
Prices Actively Quoted – Exchange Traded Contracts	\$93	\$10	\$(2)	\$-	\$-	\$-	\$101
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(9)	(63)	(17)	13	6	-	(70)
Prices Based on Models and Other Valuation Methods (b)	<u>(49)</u>	<u>(9)</u>	<u>7</u>	<u>16</u>	<u>13</u>	<u>36</u>	<u>14</u>
Total	<u>\$35</u>	<u>\$(62)</u>	<u>\$(12)</u>	<u>\$29</u>	<u>\$19</u>	<u>\$36</u>	<u>\$45</u>

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Modeled – 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 are limited, such valuations are classified as modeled.

(c) For Utility Operations, there is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. \$17 million of this mark-to-market value is in 2009 and \$16 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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, 2003**

<u>Domestic</u>	<u>Transaction Class</u>	<u>Market/Region</u>	<u>Tenor (in months)</u>
Natural Gas	Futures	NYMEX Henry Hub	72
	Physical Forwards	Gulf Coast, Texas	12
	Swaps	Gas East – Northeast, Mid-continent	
		Gulf Coast, Texas	15
	Swaps	Gas West – Rocky Mountains, West Coast	15
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	24
	Physical Forwards	Power East – Cinergy	60
	Physical Forwards	Power East – PJM	48
	Physical Forwards	Power East – NYPP	24
	Physical Forwards	Power East – NEPOOL	12
	Physical Forwards	Power East – ERCOT	24
	Physical Forwards	Power East – TVA	48
	Physical Forwards	Power East – Com Ed	24
	Physical Forwards	Power East – Entergy	48
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	60
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO2	24
Coal	Physical Forwards	PRB,NYMEX,CSX	24
<u>International</u>			
Power	Forwards and Options	United Kingdom	24
Coal	Forward Purchases and Sales	United Kingdom	15
	Swaps	Europe	36
Freight	Swaps	Europe	24

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) 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 such as 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 fair value hedges and cash flow hedges to mitigate changes in interest rates or fair values on short and long-term debt when management deems it necessary. 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. International subsidiaries use currency swaps to hedge exchange rate fluctuations of debt denominated in foreign currencies. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place (However, given that under SFAS 133 only cash flow hedges are recorded in Accumulated Other Comprehensive Income (AOCI), the table does not provide an all-encompassing picture of our hedging activity). The table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges).

Information on energy merchant activities is presented separately from interest rate, foreign currency risk management activities and other hedging activities. In accordance with GAAP, all amounts are presented net of related income taxes.

**Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss)
On the Balance Sheet as of December 31, 2003**

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power and Gas	\$(65)	\$(58)
Foreign Currency	(20)	(20)
Interest Rate	(9)	(8)
Total	<u>\$(94)</u>	<u>\$(86)</u>

**Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003**

	Power and Gas	Foreign Currency	Interest Rate	Consolidated
	(in millions)			
Beginning Balance, December 31, 2002	\$(3)	\$(1)	\$(12)	\$(16)
Changes in Fair Value (c)	(64)	(19)	4	(79)
Reclassifications from AOCI to Net Income (d)	2	-	(1)	1
Ending Balance, December 31, 2003	<u>\$(65)</u>	<u>\$(20)</u>	<u>\$(9)</u>	<u>\$(94)</u>

- (a) "Accumulated Other Comprehensive Income (Loss) After Tax" – Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.
- (b) "Portion Expected to be Reclassified to Earnings During the Next 12 Months" – Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.
- (c) "Changes in Fair Value" – Changes in the fair value of derivatives designated as cash flow hedges not yet reclassified into net income, pending the hedged items affecting net income. Amounts are reported net of related income taxes.
- (d) "Reclassifications from AOCI to Net Income" – Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continue 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 Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. Our independent 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. We believe that credit exposure with any one counterparty is not material to our financial condition at December 31, 2003. At December 31, 2003, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 16%, expressed in terms of net MTM assets and net receivables. The increase in non-investment grade credit quality was largely due to an increase in coal and freight exposures related to our U.K. investments. As of December 31, 2003, the following table approximates our counterparty credit quality and exposure based on netting across commodities and instruments:

Counterparty Credit Quality:	Exposure Before Credit Collateral	Credit Collateral	Net Exposure (in millions)	Number of Counterparties > 10%	Net Exposure of Counterparties > 10%
Investment Grade	\$931	\$29	\$902	1	\$135
Split Rating	47	-	47	1	40
Non-Investment Grade	276	136	140	2	71
No External Ratings:					
Internal Investment					
Grade	480	5	475	3	207
Internal Non-Investment					
Grade	185	48	137	2	51
Total	<u>\$1,919</u>	<u>\$218</u>	<u>\$1,701</u>	<u>9</u>	<u>\$504</u>

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. This information is forward-looking and provided on a prospective basis through December 31, 2006. 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 megawatt hours of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information Estimated Next Three Years As of December 31, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>
Estimated Plant Output Hedged	90%	92%	92%

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, 2003, 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 year-to-date:

VaR Model

<u>December 31, 2003</u>				<u>December 31, 2002</u>			
(in millions)				(in millions)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$11	\$19	\$ 7	\$4	\$5	\$24	\$12	\$4

The high VaR for 2003 occurred in late February 2003 during a period when natural gas and power prices experienced high levels and extreme volatility. Within a few days, the VaR returned to levels more representative of the average VaR for the year.

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics

	<u>December 31, 2003</u>	<u>Average for Year-to-Date 2003</u>	<u>High for Year-to-Date 2003</u>	<u>Low for Year-to-Date 2003</u>
		(in millions)		
95% Confidence Level, Ten-Day Holding Period	\$41	\$27	\$71	\$16
99% Confidence Level, One-Day Holding Period	\$17	\$11	\$30	\$ 7

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 \$1.013 billion at December 31, 2003 and \$527 million at December 31, 2002. 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 or consolidated financial position.

We are 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 area of Texas (effective January 1, 2002) or frozen by a settlement agreement in West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts we are subject to market price risk. We continue to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas. Fuel clauses are active again in Michigan and Texas, effective January 1, 2004 and March 1, 2004, respectively.

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 and to a lesser degree other commodities, principally coal and freight. 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 his staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001
(in millions, except per-share amounts)

	<u>2003</u>	<u>2002</u>	<u>2001</u>
REVENUES			
Utility Operations	\$10,871	\$10,446	\$10,546
Gas Operations	3,097	2,071	1,797
Other	577	791	410
TOTAL	<u>14,545</u>	<u>13,308</u>	<u>12,753</u>
EXPENSES			
Fuel for Electric Generation	3,053	2,577	3,225
Purchased Electricity for Resale	707	532	296
Purchased Gas for Resale	2,850	1,946	1,443
Maintenance and Other Operation	3,673	4,065	3,666
Asset Impairments and Other Related Charges	650	318	-
Depreciation and Amortization	1,299	1,348	1,233
Taxes Other Than Income Taxes	681	718	667
TOTAL	<u>12,913</u>	<u>11,504</u>	<u>10,530</u>
OPERATING INCOME	<u>1,632</u>	<u>1,804</u>	<u>2,223</u>
Other Income	387	461	371
INTEREST AND OTHER CHARGES			
Investment Value Losses	70	321	-
Other Expenses	227	323	225
Interest	814	775	833
Preferred Stock Dividend Requirements of Subsidiaries	9	11	10
Minority Interest in Finance Subsidiary	19	35	13
TOTAL	<u>1,139</u>	<u>1,465</u>	<u>1,081</u>
INCOME BEFORE INCOME TAXES	880	800	1,513
Income Taxes	358	315	553
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	522	485	960
DISCONTINUED OPERATIONS (Net of Tax)	(605)	(654)	41
EXTRAORDINARY LOSS (Net of Tax)	-	-	(48)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)			
Goodwill and Other Intangible Assets	-	(350)	18
Accounting for Risk Management Contracts	(49)	-	-
Asset Retirement Obligations	242	-	-
NET INCOME (LOSS)	<u>\$110</u>	<u>\$(519)</u>	<u>\$971</u>
AVERAGE NUMBER OF SHARES OUTSTANDING	<u>385</u>	<u>332</u>	<u>322</u>
EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes	\$1.35	\$1.46	\$2.98
Discontinued Operations	(1.57)	(1.97)	0.13
Extraordinary Loss	-	-	(0.16)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	<u>\$0.29</u>	<u>\$(1.57)</u>	<u>\$3.01</u>
CASH DIVIDENDS PAID PER SHARE	<u>\$1.65</u>	<u>\$2.40</u>	<u>\$2.40</u>

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	\$1,182	\$1,199
Accounts Receivable:		
Customers	1,155	1,553
Accrued Unbilled Revenues	596	551
Miscellaneous	83	93
Allowance for Uncollectible Accounts	<u>(124)</u>	<u>(108)</u>
Total Receivables	<u>1,710</u>	<u>2,089</u>
Fuel, Materials and Supplies	991	938
Risk Management Assets	766	850
Margin Deposits	119	110
Other	<u>129</u>	<u>132</u>
TOTAL	<u>4,897</u>	<u>5,318</u>
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,112	13,678
Transmission	6,130	5,866
Distribution	9,902	9,573
Other (including gas, coal mining and nuclear fuel)	3,584	3,656
Construction Work in Progress	<u>1,305</u>	<u>1,354</u>
TOTAL	<u>36,033</u>	<u>34,127</u>
Less: Accumulated Depreciation and Amortization	<u>14,004</u>	<u>13,539</u>
TOTAL-NET	<u>22,029</u>	<u>20,588</u>
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,548	2,688
Securitized Transition Assets	689	735
Spent Nuclear Fuel and Decommissioning Trusts	982	871
Investments in Power and Distribution Projects	212	283
Goodwill	78	241
Long-term Risk Management Assets	494	758
Other	<u>733</u>	<u>792</u>
TOTAL	<u>6,736</u>	<u>6,368</u>
Assets Held for Sale	3,082	3,601
Assets of Discontinued Operations	-	15
TOTAL ASSETS	<u>\$36,744</u>	<u>\$35,890</u>

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	\$1,337	\$1,892
Short-term Debt	326	2,739
Long-term Debt Due Within One Year*	1,779	1,327
Risk Management Liabilities	631	961
Accrued Taxes	620	556
Accrued Interest	207	181
Customer Deposits	379	186
Other	703	814
TOTAL	<u>5,982</u>	<u>8,656</u>
NON-CURRENT LIABILITIES		
Long-term Debt*	12,322	8,863
Long-term Risk Management Liabilities	335	435
Deferred Income Taxes	3,957	3,916
Regulatory Liabilities and Deferred Investment Tax Credits	2,259	939
Asset Retirement Obligations and Nuclear Decommissioning Trusts	651	638
Employee Benefits and Pension Obligations	667	987
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	176	185
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	76	-
Deferred Credits and Other	508	1,691
TOTAL	<u>20,951</u>	<u>17,654</u>
Liabilities Held for Sale	1,876	1,279
Liabilities of Discontinued Operations	-	12
TOTAL LIABILITIES	<u>28,809</u>	<u>27,601</u>
Cumulative Preferred Stocks of Subsidiaries not Subject to Mandatory Redemption	61	-
Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary		
Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries	-	321
Minority Interest in Finance Subsidiary	-	759
Cumulative Preferred Stocks of Subsidiaries	-	145
Commitments and Contingencies		
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value \$6.50:		
	<u>2003</u>	<u>2002</u>
Shares Authorized.	600,000,000	600,000,000
Shares Issued.	404,016,413	347,835,212
(8,999,992 shares were held in treasury at December 31, 2003 and 2002)	2,626	2,261
Paid-in Capital	4,184	3,413
Retained Earnings	1,490	1,999
Accumulated Other Comprehensive Income (Loss)	(426)	(609)
TOTAL	<u>7,874</u>	<u>7,064</u>
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	<u>\$36,744</u>	<u>\$35,890</u>

* See Accompanying Schedules

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, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income (Loss)	\$110	\$(519)	\$971
Plus: Discontinued Operations	<u>605</u>	<u>654</u>	<u>(41)</u>
Income from Continuing Operations	715	135	930
Adjustments for Noncash Items:			
Depreciation and Amortization	1,299	1,375	1,267
Deferred Income Taxes	163	63	151
Deferred Investment Tax Credits	(33)	(31)	(29)
Pension and Postemployment Benefits Reserves	(74)	39	(234)
Cumulative Effect of Accounting Changes	(193)	350	(18)
Asset and Investment Value Impairments and Other Related Charges	720	639	-
Extraordinary Loss	-	-	48
Amortization of Deferred Property Taxes	(2)	(16)	43
Amortization of Cook Plant Restart Costs	40	40	40
Mark to Market of Risk Management Contracts	(122)	275	(294)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable, net	363	(238)	1,769
Fuel, Materials and Supplies	(71)	(102)	(82)
Accounts Payable	(632)	(21)	(469)
Taxes Accrued	87	(222)	(150)
Over/Under Fuel Recovery	138	13	340
Change in Other Assets	(162)	(78)	(171)
Change in Other Liabilities	<u>72</u>	<u>(154)</u>	<u>(323)</u>
Net Cash Flows From Operating Activities	<u>2,308</u>	<u>2,067</u>	<u>2,818</u>
INVESTING ACTIVITIES			
Construction Expenditures	(1,358)	(1,685)	(1,646)
Business Acquisitions	-	-	(1,269)
Investment in Discontinued Operations, net	(615)	-	(983)
Proceeds from Sale of Assets	82	1,263	648
Other	<u>3</u>	<u>44</u>	<u>(42)</u>
Net Cash Flows Used For Investing Activities	<u>(1,888)</u>	<u>(378)</u>	<u>(3,292)</u>
FINANCING ACTIVITIES			
Issuance of Common Stock	1,142	656	11
Issuance of Long-term Debt	4,761	2,893	2,787
Issuance of Minority Interest	-	-	744
Issuance of Equity Unit Senior Notes	-	334	-
Change in Short-term Debt, net	(2,781)	(1,248)	(778)
Retirement of Long-term Debt	(2,707)	(2,513)	(1,549)
Retirement of Preferred Stock	(9)	(10)	(5)
Retirement of Minority Interest	(225)	-	-
Dividends Paid on Common Stock	<u>(618)</u>	<u>(793)</u>	<u>(773)</u>
Net Cash Flows From (Used For) Financing Activities	<u>(437)</u>	<u>(681)</u>	<u>437</u>
Effect of Exchange Rate Change on Cash	<u>-</u>	<u>(3)</u>	<u>(1)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	1,005	(38)
Cash and Cash Equivalents at Beginning of Period	<u>1,199</u>	<u>194</u>	<u>232</u>
Cash and Cash Equivalents at End of Period	<u>\$1,182</u>	<u>\$1,199</u>	<u>\$194</u>
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	\$(10)	\$(116)	\$29
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	<u>23</u>	<u>139</u>	<u>110</u>
Cash and Cash Equivalents from Discontinued Operations – End of Period	<u>\$13</u>	<u>\$23</u>	<u>\$139</u>

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME (LOSS)
(in millions)

	<u>Common Stock</u>		<u>Paid-in</u>	<u>Retained</u>	<u>Accumulated</u> <u>Other</u>	
	<u>Shares</u>	<u>Amount</u>	<u>Capital</u>	<u>Earnings</u>	<u>Comprehensive</u> <u>Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	331	\$2,152	\$2,915	\$3,090	\$(103)	\$8,054
Issuance of Common Stock		1	9			10
Common Stock Dividends				(773)		(773)
Other			(18)	8		(10)
TOTAL						<u>7,281</u>
<u>COMPREHENSIVE INCOME (LOSS)</u>						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					(14)	(14)
Unrealized Losses on Cash Flow Hedges					(3)	(3)
Minimum Pension Liability					(6)	(6)
NET INCOME				971		<u>971</u>
TOTAL COMPREHENSIVE INCOME						<u>948</u>
DECEMBER 31, 2001	331	\$2,153	\$2,906	\$3,296	\$(126)	\$8,229
Issuance of Common Stock	17	108	568			676
Common Stock Dividends				(793)		(793)
Common Stock Expense			(30)			(30)
Other			(31)	15		(16)
TOTAL						<u>8,066</u>
<u>COMPREHENSIVE INCOME (LOSS)</u>						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					117	117
Unrealized Losses on Cash Flow Hedges					(13)	(13)
Unrealized Losses on Securities Available for Sale					(2)	(2)
Minimum Pension Liability					(585)	(585)
NET LOSS				(519)		<u>(519)</u>
TOTAL COMPREHENSIVE INCOME (LOSS)						<u>(1,002)</u>
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						<u>7,581</u>
<u>COMPREHENSIVE INCOME (LOSS)</u>						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					106	106
Unrealized Losses on Cash Flow Hedges					(78)	(78)
Unrealized Gains on Securities Available for Sale					1	1
Minimum Pension Liability					154	154
NET INCOME				110		<u>110</u>
TOTAL COMPREHENSIVE INCOME						<u>293</u>
DECEMBER 31, 2003	<u>404</u>	<u>\$2,626</u>	<u>\$4,184</u>	<u>\$1,490</u>	<u>\$(426)</u>	<u>\$7,874</u>

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES
December 31, 2003 and 2002

December 31, 2003				
	<u>Call</u>	<u>Shares</u>	<u>Shares</u>	<u>Amount</u>
	<u>Price Per Share(a)</u>	<u>Authorized(b)</u>	<u>Outstanding(d)</u>	<u>(in millions)</u>
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	\$102-\$110	1,525,903	607,940	<u>\$61</u>
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	\$100	1,950,000	278,100	28
6.25% - 6.875% (c)	\$100	1,650,000	482,450	<u>48</u>
Total Subject to Mandatory Redemption (c)				<u>76</u>
Total Preferred Stock				<u>\$137 (e)</u>

December 31, 2002				
	<u>Call</u>	<u>Shares</u>	<u>Shares</u>	<u>Amount</u>
	<u>Price Per Share(a)</u>	<u>Authorized(b)</u>	<u>Outstanding(d)</u>	<u>(in millions)</u>
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	\$102-\$110	1,525,903	608,150	<u>\$61</u>
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	\$100	1,950,000	333,100	33
6.02% - 6.875% (c)	\$100	1,650,000	513,450	<u>51</u>
Total Subject to Mandatory Redemption (c)				<u>84</u>
Total Preferred Stock				<u>\$145</u>

- (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, 2003, the subsidiaries had 13,780,352 shares of \$100 par value preferred stock, 22,200,000 shares of \$25 par value preferred stock and 7,768,561 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 86,210 shares in 2003, 106,458 shares in 2002 and 50,000 shares in 2001.
- (e) Due to the implementation of SFAS 150 in July 2003, Cumulative Preferred Stocks of Subsidiaries is no longer presented as one line item on the balance sheet. SFAS 150 has required us to present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a liability. Cumulative Preferred Stocks of Subsidiaries Not Subject to Mandatory Redemption will continue to be reported on the balance sheet in the "mezzanine" section.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2003 and 2002

<u>Maturity</u>	<u>Weighted Average</u> <u>Interest Rate</u> <u>December 31, 2003</u>	<u>Interest Rates at December 31,</u> <u>2003</u> <u>2002</u>		<u>December 31,</u> <u>2003</u> <u>2002</u> (in millions)	
FIRST MORTGAGE BONDS (a)					
2003-2004	7.40%	6.125%-7.85%	6.00%-7.85%	\$231	\$648
2005-2008	6.90%	6.20%-8.00%	6.20%-8.00%	463	463
2022-2025	7.28%	6.875%-8.00%	6.875%-8.70%	246	773
INSTALLMENT PURCHASE CONTRACTS (b)(f)					
2003-2009	3.74%	2.15%-6.90%	3.75%-7.70%	395	396
2011-2030	4.92%	1.10%-8.20%	1.35%-8.20%	1,631	1,284
NOTES PAYABLE (c)(f)					
2003-2017	5.20%	1.537%-15.45%	6.225%-9.60%	1,518	214
SENIOR UNSECURED NOTES					
2003-2005	5.10%	2.43%-7.45%	2.12%-7.45%	1,359	1,834
2006-2015	5.49%	3.60%-6.91%	4.31%-6.91%	4,873	2,295
2032-2038	6.41%	5.625%-7.375%	6.00%-7.375%	1,765	690
JUNIOR DEBENTURES					
2025-2038	-	-	7.60%-8.72%	-	205
SECURITIZATION BONDS					
2005-2016	5.53%	3.54%-6.25%	3.54%-6.25%	746	797
NOTES PAYABLE TO TRUST (d)					
2037-2043	7.06%	5.25-8.00%	-	331	-
EQUITY UNIT SENIOR NOTES (e)					
2007	5.75%	5.75%	5.75%	345	345
OTHER LONG-TERM DEBT (g)				247	247
Equity Unit Contract Adjustment Payments				19	31
Unamortized Discount (net)				(68)	(32)
Total Long-term Debt Outstanding				<u>14,101</u>	<u>10,190</u>
Less Portion Due Within One Year				<u>1,779</u>	<u>1,327</u>
Long-term Portion				<u><u>\$12,322</u></u>	<u><u>\$8,863</u></u>

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment.

(b) 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.

(c) 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.

(d) Notes Payable to Trust is a result of a deconsolidation of TCC, PSO and SWEPCo's trusts effective July 1, 2003 due to the implementation of FIN 46. See Notes 2 and 17 for further information.

(e) In May 2005, the interest rate on these Equity Unit Senior Notes can be reset through a remarketing.

(f) Installment Purchase Contracts and Notes Payable include \$257 million and \$185 million, respectively, due to the implementation of FIN 46 (see Note 2). Notes Payable includes \$496 million of a merchant power generation facility which was consolidated as of December 31, 2003 (see Notes 10 and 16).

(g) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 7) and a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2003 IS PAYABLE AS FOLLOWS:

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u> (in millions)	<u>2008</u>	<u>Later Years</u>	<u>TOTAL</u>
Principal Amount	\$1,779	\$1,273	\$2,187	\$1,124	\$587	\$7,200	\$14,150
Equity Unit Contract Adjustment Payments							19
Unamortized Discount							(68)
							<u><u>\$14,101</u></u>

AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES
INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes
3. Goodwill and Other Intangible Assets
4. Rate Matters
5. Effects of Regulation
6. Customer Choice and Industry Restructuring
7. Commitments and Contingencies
8. Guarantees
9. Sustained Earnings Improvement Initiative
10. Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used
11. Benefit Plans
12. Stock-Based Compensation
13. Business Segments
14. Derivatives, Hedging and Financial Instruments
15. Income Taxes
16. Leases
17. Financing Activities
18. Unaudited Quarterly Financial Information
19. Subsequent Events (Unaudited)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business conducted by our eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act 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.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and Europe. In addition, our domestic operations include non-regulated independent power and cogeneration facilities, coal mining and intra-state natural gas operations in Louisiana and Texas.

International operations include the generation and supply of power in the United Kingdom, and to a lesser extent in Mexico, Australia and China. These operations are either wholly-owned or partially-owned by our various subsidiaries.

We also conduct domestic barging operations, provide various energy related services and furnish communications-related services domestically.

During 2003 we announced plans to significantly restructure and dispose of many of our non-regulated operations. See Note 10 for a discussion of the impacts of these plans on our organization.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

We are subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates. The prices charged by foreign subsidiaries located in China and Mexico are regulated by the authorities of those countries and are generally subject to price controls.

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. 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 Other Income. We also have generating units that are jointly owned with unaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and the investments 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. 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. 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, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

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

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other 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 deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

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 non-regulated 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 not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, generally using composite rates by functional class as follows:

<u>Functional Class of Property</u>	<u>Annual Composite Depreciation Rates Ranges</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
Production:			
Steam-Nuclear	2.5% to 3.4%	2.5% to 3.4%	2.5% to 3.4%
Steam-Fossil-Fired	2.3% to 4.6%	2.6% to 4.5%	2.5% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%	1.9% to 3.4%	1.9% to 3.4%
Transmission	1.7% to 2.8%	1.7% to 3.0%	1.7% to 3.1%
Distribution	3.3% to 4.2%	3.3% to 4.2%	2.7% to 4.2%
Other	1.8% to 16.7%	1.8% to 9.9%	1.8% to 15.0%

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 \$0.25 per ton in 2003, \$0.32 per ton in 2002 and \$2.06 per ton in 2001. In 2002, certain coal-mining assets were impaired by \$60

million leading to the decline in amortization rates in 2003. In 2001, an AEP subsidiary sold coal mines in Ohio and West Virginia leading to the decline in amortization rates in 2002.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value 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.

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost. Non-trading gas inventory is carried at the lower of cost or market. During 2003 a fair value hedging strategy was implemented for certain non-trading gas and coal inventory. Changes in the fair value of hedged inventory are recorded to the extent offsetting hedges are designated against that inventory.

Accounts Receivable

Customer accounts receivable primarily includes 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 latest billings.

AEP Credit, Inc. factors accounts receivable for 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. 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, allowing the receivables to be taken off of the company's balance sheet. See Note 17 "Financing Activities" for further details.

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. which are included in our consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation." Although the effects of foreign currency fluctuations are mitigated by the fact that expenses of foreign subsidiaries are generally incurred in the same currencies in which sales are generated, the reported results of operations of our foreign subsidiaries are affected by changes in foreign currency exchange rates and, as compared to prior periods, will be higher or lower depending upon a weakening or strengthening of the U.S. dollar. 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 impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates, is shown on our Consolidated

Statements of Cash Flows in Effect of Exchange Rate Change on Cash. Actual currency transaction gains and losses are recorded in income when they occur.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. The amount of under-recovered fuel costs deferred under fuel clauses as a regulatory asset was \$51 million at December 31, 2003 and \$148 million at December 31, 2002. The amount of over-recovered fuel costs deferred under fuel clauses as a regulatory liability was \$132 million at December 31, 2003 and \$90 million at December 31, 2002. See Note 5 "Effects of Regulation" for further information.

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 timely reflected in rates through the fuel cost adjustment clauses in place in those states. 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. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. Changes in fuel costs also impact earnings for certain of our Independent Power Producer generating units that do not have long-term contracts for their fuel supply. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

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 through regulated revenues in the same accounting period. Regulatory liabilities or regulatory assets are also recorded for unrealized 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 regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal 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.

Domestic Gas Pipeline and Storage Activities

Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and that are accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in 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 mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into 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.

After January 1, 2003, we use mark-to-market 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. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

We use the mark-to-market method of accounting for derivative contracts. Unrealized gains and losses prior to settlement, resulting from revaluation of these contracts to fair value during the period, are recognized currently. When the derivative contracts are settled and gains and losses are realized, the previously recorded unrealized gains and losses from mark-to-market valuations are reversed.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement 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 and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 14).

The fair values of derivative instruments accounted for using mark-to-market accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a

contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Construction Projects for Outside Parties

Our entities engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue in proportion to costs incurred compared to total estimated costs.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, we enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2003 or 2002.

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 maintenance costs with their recovery in cost-based regulated revenues.

Other Income and Other Expenses

Non-operational revenue including the nonregulated business activities of our utilities, equity earnings of non-consolidated subsidiaries, gains on dispositions of property, interest and dividends, AFUDC and miscellaneous income, are reported in Other Income. Non-operational expenses including nonregulated business activities of our utilities, losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses, are reported in Other Expenses.

AEP Consolidated Other Income and Deductions:

	<u>2003</u>	<u>December 31,</u> <u>2002</u> (in millions)	<u>2001</u>
Other Income:			
Equity Earnings (Loss)	\$10	\$(15)	\$30
Non-operational Revenue	129	201	184
Interest	42	26	48
Gain on Sale of Frontera	-	-	73
Gain on Sale of REPs (Mutual Energy Companies)	39	129	-
Other	<u>167</u>	<u>120</u>	<u>36</u>
Total Other Income	<u>\$387</u>	<u>\$461</u>	<u>\$371</u>
Other Expenses:			
Property Taxes	\$20	\$20	\$15
Non-operational Expenses	112	179	76
Fiber Optic and Datapult Exit Costs	-	-	49
Provision for Loss - Airplane	-	-	14
Other	<u>95</u>	<u>124</u>	<u>71</u>
Total Other Expenses	<u>\$227</u>	<u>\$323</u>	<u>\$225</u>

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

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 customer. 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 plant are generally 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. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Other Income and Other Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

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 amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

When we acquire businesses we record the fair value of any acquired goodwill and other intangible assets. 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. Intangible assets with finite lives are amortized over their respective estimated lives to their estimated residual values.

The policies described above became effective with our adoption of a new accounting standard for goodwill (SFAS 142). For all business combinations with an acquisition date before July 1, 2001, we amortized goodwill and intangible assets with indefinite lives through December 2001, and then ceased amortization. The goodwill associated with those business combinations with an acquisition date before July 1, 2001 was amortized on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which was amortized on a straight-line basis over 10 years. Intangible assets with finite lives continue to be amortized over their respective estimated lives ranging from 2 to 10 years.

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 fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) 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

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-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 are included in Assets Held for Sale for amounts relating to the Texas Plants. See “Assets Held for Sale” section of Note 10 for further information regarding the Texas Plants. 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.

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 (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

<u>Components</u>	<u>December 31,</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in millions)	
Foreign Currency Translation Adjustments	\$110	\$4	\$(113)
Unrealized Losses on Securities Available for Sale	(1)	(2)	-
Unrealized Losses on Cash Flow Hedges	(94)	(16)	(3)
Minimum Pension Liability	<u>(441)</u>	<u>(595)</u>	<u>(10)</u>
Total	<u>\$(426)</u>	<u>\$(609)</u>	<u>\$(126)</u>

Stock Based Compensation Plans

At December 31, 2003, we have two stock-based employee compensation plans with outstanding stock options, which are described more fully in Note 12. No stock option expense is reflected in our earnings, as 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 non-employee members of the Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors permits directors to choose to defer up to 100 percent of their annual Board retainer in stock units, and 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.

We do not currently intend to adopt the fair-value-based method of accounting for stock options. The following table shows the effect on our Net Income (Loss) and Earnings (Loss) per Share as if we had applied fair value measurement and recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation awards:

	<u>Year Ended December 31,</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions, except per share data)		
Net Income (Loss), as reported	\$110	\$(519)	\$971
Add: Stock-based compensation expense included in reported net income, net of related tax effects	2	(5)	3
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	<u>(7)</u>	<u>(4)</u>	<u>(15)</u>
Pro Forma Net Income (Loss)	<u>\$105</u>	<u>\$(528)</u>	<u>\$959</u>
Earnings (Loss) per Share:			
Basic – as Reported	\$0.29	\$(1.57)	\$3.01
Basic – Pro Forma (a)	\$0.27	\$(1.59)	\$2.98
Diluted – as Reported	\$0.29	\$(1.57)	\$3.01
Diluted – Pro Forma (a)	\$0.27	\$(1.59)	\$2.97

(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 effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been anti-dilutive.

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:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions – except per share amounts)		
Weighted Average Shares:			
Average Common Shares Outstanding	385	332	322
Assumed Conversion of Dilutive Stock Options (see Note 12)	<u>-</u>	<u>-</u>	<u>1</u>
Diluted Average Common Shares Outstanding	<u>385</u>	<u>332</u>	<u>323</u>

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Our basic and diluted EPS are the same in 2003, 2002 and 2001 since the effect on weighted average common shares outstanding is minimal.

Had we reported net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 5.6 million, 8.8 million and 0.7 million shares of common stock were outstanding at December 31, 2003, 2002 and 2001, 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 is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of our common stock exceeds \$49.08 per share. There were no dilutive effects from equity units at December 31, 2003 and 2002. If our common stock value exceeds \$49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares. Also see Note 17.

Supplementary Information

	<u>Year Ended December 31,</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
AEP Consolidated Purchased Power – Ohio Valley Electric Corporation (44.2% owned by AEP System)	\$147	\$142	\$127
Cash was paid for:			
Interest (net of capitalized amounts)	\$741	\$792	\$972
Income Taxes	\$163	\$336	\$569
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	\$25	\$6	\$17
Assumption of Liabilities Related to Acquisitions	\$-	\$1	\$171
Increase in assets and liabilities resulting from:			
Consolidation of VIEs due to the adoption of FIN 46 (see Note 2)	\$547	\$-	\$-
Consolidation of merchant power generation facility (see Note 16)	\$496	\$-	\$-
Exchange of Communication Investment for Common Stock	\$-	\$-	\$5

Power Projects

We own interests of 50% or less in domestic unregulated power plants with a capacity of 1,043 MW located in Colorado, Florida and Texas. In addition to the domestic projects, we have interests of 50% or less in international power plants totaling 1,113 MW (see Note 10, “Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used”).

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in Investments in Power and Distribution Projects on our Consolidated Balance Sheets (see “Eastex” within the Dispositions section of Note 10). At December 31, 2003, five domestic power projects and three international power investments are accounted for under the equity method. The five domestic projects are combined cycle gas turbines that provide steam to a host commercial customer and are considered either Qualifying Facilities (QFs) or Exempt Wholesale Generators (EWGs) under PURPA. The three international power investments are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. Two of the international investments are power projects and the other international investment is a company which owns an interest in four additional power projects. All of the power projects accounted for under the equity method have unrelated third-party partners.

Seven of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed \$8 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits. In addition, AEP has issued letters of credit with maximum future payments of \$23 million for domestic power projects and \$69 million for international power investments.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) “Employers’ Disclosure about Pensions and Other Postretirement Benefits”

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with our 2004 quarterly financial statements or our 2004 year-end financial statements.

We will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end.

We will implement the new year-end disclosure when it becomes effective in the fourth quarter of 2004, concerning information about foreign plans, if appropriate. See Note 11 for these additional 2003 disclosures.

SFAS 142 “Goodwill and Other Intangible Assets”

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. The implementation of SFAS 142 resulted in a \$350 million after tax net transitional loss in 2002 for the U.K. and Australian operations and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 “Accounting for Asset Retirement Obligations”

We implemented SFAS 143, “Accounting for Asset Retirement Obligations,” effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for our Cook Plant and our partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds, wind farms, the U.K. Plants, and certain coal mining facilities. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143 as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect of \$45.4 million after tax for our non-regulated operations (\$38.0 million related to Ash Ponds in the Utility Operations segment, \$7.2 million related to U.K. Plants in the Investments – UK Operations segment and \$0.2 million for Wind Mills in the Investments – Other segment).

Certain of our utility operating companies have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that operating companies have now been deregulated we reversed the balance of such removal costs, totaling \$287.2 million, after tax, which resulted in a net favorable cumulative effect in 2003. We have reclassified approximately \$1.2 billion of removal costs for our utility operations from accumulated depreciation to Regulatory Liabilities and Deferred Investment Tax Credits in 2003 and to Deferred Credits and Other in 2002. In addition, \$9 million is classified as held-for-sale related to the TCC generation assets as of December 31, 2003 and 2002.

The net favorable cumulative effect of the change in accounting principle for the year ended December 31, 2003 consists of the following:

	<u>Pre-tax</u> <u>Income (Loss)</u>	<u>After-tax</u> <u>Income (Loss)</u>
	(in millions)	
Ash Ponds	\$(62.8)	\$(38.0)
U.K. Plants, Wind Mills and Coal Operations	(11.3)	(7.4)
Reversal of Cost of Removal	<u>472.6</u>	<u>287.2</u>
Total	<u>\$398.5</u>	<u>\$241.8</u>

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution and gas pipeline 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.

The following is a reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations:

	<u>Nuclear Decommissioning</u>	<u>Ash Ponds (in millions)</u>	<u>U.K. Plants, Wind Mills and Coal Operations</u>	<u>Total</u>
Asset Retirement Obligation Liability at January 1, 2003	\$718.3	\$69.8	\$37.2	\$825.3
Accretion Expense	52.6	5.6	2.3	60.5
Liabilities Incurred	-		8.3	8.3
Foreign Currency Translation	<u>-</u>	<u>-</u>	<u>5.3</u>	<u>5.3</u>
Asset Retirement Obligation Liability at December 31, 2003 including Held for Sale	770.9	75.4	53.1	899.4
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project	(218.8)	-	-	(218.8)
U.K. Plants	<u>-</u>	<u>-</u>	<u>(28.8)</u>	<u>(28.8)</u>
Asset Retirement Obligation Liability at December 31, 2003	<u>\$552.1</u>	<u>\$75.4</u>	<u>\$24.3</u>	<u>\$651.8</u>

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Consolidated Statements of Operations.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled \$845 million and \$716 million, respectively, of which \$720 million and \$618 million relating to the Cook Plant was recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling \$125 million and \$98 million as of December 31, 2003 and 2002, respectively, was classified as Assets Held for Sale in our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 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, 2002 and 2001, the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted at the beginning of each period was \$825 million and \$769 million, respectively.

SFAS 144 “Accounting for the Impairment or Disposal of Long-lived Assets”

In August 2001, the FASB issued SFAS 144, “Accounting for the Impairment or Disposal of Long-lived Assets” which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, “Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of.” We adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections”

In April 2002, the FASB issued SFAS 145, “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections” (SFAS 145). SFAS 145 rescinds SFAS 4, “Reporting Gains and Losses from Extinguishment of Debt,” effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003,

we reclassified Extraordinary Losses (Net of Tax) on TCC's reacquired debt of \$2 million for 2001 to Other Expenses.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. We adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify for the normal purchase and sale exemption. SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, we implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a Non-Current Liability. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as interest expense. In accordance with SFAS 150, dividends from prior periods remain classified as preferred stock dividends (a component of Preferred Stock Dividend Requirements of Subsidiaries).

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize liabilities related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003) "Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated Caddis Partners, LLC (Caddis). At December 31, 2002 \$759 million was reported as a Minority Interest in Finance Subsidiary. At December 31, 2003 \$527 million is reported as a note payable to Caddis, a component of Long-Term Debt. See Note 17 "Financing Activities" for further disclosures.

On July 1, 2003, we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the \$321 million net amount reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, \$331 million is reported as Notes Payable to Trust (included in Long-term Debt) and \$10 million is reported in Other Non-Current Assets at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine (\$77.8 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG (\$469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 16 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. We have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into 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. We recorded a \$49 million loss, net of income tax, as a cumulative effect of accounting change.

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, we recorded and reported upon settlement, sales under forward risk management contracts as revenues; we also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, we reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on our financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether our plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to our accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, we elected to defer any potential effects of the Act until authoritative guidance on the accounting for the federal subsidy is issued. Our measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. We cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. We recorded a \$49 million after tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003 (\$12 million in Utility Operations, \$22 million in Investments – Gas Operations and \$15 million in Investments – UK Operations segments). This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

The effect of initially adopting the DIG guidance at July 1, 2001 was a favorable earnings mark-to-market after tax effect of \$18 million (net of tax of \$2 million). It was reported as a cumulative effect of an accounting change on our Consolidated Statements of Operations (included in Investments - Other segment).

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, we recorded \$242 million in after-tax income as a cumulative effect of accounting change for Asset Retirement Obligations.

Goodwill and Other Intangible Assets

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 in 2002 resulted in a \$350 million net transitional loss for our U.K. and Australian operations (included in the Investments – Other segment) and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3, "Goodwill and Other Intangible Assets" for further details).

See table below for details of the Cumulative Effect of Accounting Changes:

Description	Year Ended December 31,		
	2003	2002 (in millions)	2001
Accounting for Risk Management Contracts (EITF 02-3)	\$(49)	\$-	\$-
Asset Retirement Obligations (SFAS 143)	242	-	-
Goodwill and Other Intangible Assets	-	(350)	-
Accounting for Risk Management Contracts (DIG Guidance)	-	-	18
Total	<u><u>\$193</u></u>	<u><u>\$(350)</u></u>	<u><u>\$18</u></u>

EXTRAORDINARY ITEMS

In 2001, we recorded an extraordinary item for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of our business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of \$48 million (net of tax of \$20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

GOODWILL

The changes in our carrying amount of goodwill for the years ended December 31, 2003 and 2002 by operating segment are:

	<u>Investments</u>				
	<u>Utility Operations</u>	<u>Gas Operations</u>	<u>UK Operations</u> (in millions)	<u>Other</u>	<u>AEP Consolidated</u>
Balance at January 1, 2002					
(including Assets Held for Sale)	\$37.1	\$340.1	\$-	\$14.9	\$392.1
Goodwill acquired	-	-	2.3	-	2.3
Changes to Goodwill due to					
Purchase price adjustments	-	(33.8)	172.5	42.4	181.1
Impairment losses	-	-	(170.0)	(15.9)	(185.9)
Foreign currency exchange rate changes	-	-	6.4	-	6.4
Balance at December 31, 2002					
(including Assets Held for Sale)	37.1	306.3	11.2	41.4	396.0
Less: Assets Held for Sale, Net (a)	-	(143.8)	(11.2)	-	(155.0)
Balance at December 31, 2002					
(excluding Assets Held for Sale)	<u>\$37.1</u>	<u>\$162.5</u>	<u>\$-</u>	<u>\$41.4</u>	<u>\$241.0</u>
Balance at January 1, 2003					
(including Assets Held for Sale)	\$37.1	\$306.3	\$11.2	\$41.4	\$396.0
Impairment losses	-	(291.4)	(12.2)	-	(303.6)
Foreign currency exchange rate changes	-	-	1.0	-	1.0
Balance at December 31, 2003					
(including Assets Held for Sale)	37.1	14.9	-	41.4	93.4
Less: Assets Held for Sale, Net (a)	-	(14.9)	-	-	(14.9)
Balance at December 31, 2003					
(excluding Assets Held for Sale)	<u>\$37.1</u>	<u>\$-</u>	<u>\$-</u>	<u>\$41.4</u>	<u>\$78.5</u>

(a) On our Consolidated Balance Sheets, amounts related to entities classified as held for sale are excluded from Goodwill and are reported within Assets Held for Sale (see Note 10). The following entities classified as held for sale had goodwill or goodwill impairments during the years ended December 31, 2003 or 2002:

- Jefferson Island (Investments – Gas Operations segment) – \$14.4 million and \$143.3 million balances in goodwill at December 1, 2003 and 2002, respectively. During 2003, we recognized a goodwill impairment loss of \$128.9 million.
- LIG Chemical (Investments – Gas Operations segment) – \$0.5 million balance in goodwill at December 31, 2003 and 2002.
- U.K. Coal Trading (Investments – UK Operations segment) – \$11.2 million balance in goodwill at December 31, 2002. In 2003, we recognized a goodwill impairment loss of \$12.2 million related to the impairment study (impairment in 2003 was greater than December 31, 2002 balance due to changes in foreign currency translation rates).
- U.K. Generation (Investments – UK Operations segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a goodwill impairment loss of \$166.0 million related to the impairment study.
- AEP Coal (Investments – Other segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a \$3.6 million impairment loss related to the impairment study.

Accumulated amortization of goodwill was approximately \$1 million and \$9 million at December 31, 2003 and 2002, respectively. The decrease of \$8 million between years is related to the impairment of goodwill on Houston Pipe Line Company and AEP Energy Services.

In the fourth quarter of 2003, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections and other market value indicators. As a result of the tests, we recognized a \$162.5 million goodwill impairment loss related to Houston Pipe Line Company (\$150.4 million) and AEP Energy Services (\$12.1 million).

During 2002, changes to goodwill were due to purchase price adjustments of \$6.7 million primarily related to our acquisition of Houston Pipe Line Company, MEMCO and Nordic Trading (see Note 10).

In the first quarter of 2002, we recognized a goodwill impairment loss of \$12.3 million for all goodwill related to Gas Power Systems (see Note 10).

In the fourth quarter of 2002, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections. As a result of the tests, we recognized a goodwill impairment loss of \$4.0 million related to Nordic Trading (see Note 10).

The transitional impairment loss related to SEEBOARD and CitiPower goodwill, which is reported as Cumulative Effect of Accounting Changes in 2002, is excluded from the above schedule.

The following tables show the transitional disclosures to adjust our reported net income (loss) and earnings (loss) per share to exclude amortization expense recognized in prior periods related to goodwill and intangible assets that are no longer being amortized.

Net Income (Loss)

	Year Ended December 31,		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
Reported Net Income (Loss)	\$110	\$(519)	\$971
Add back: Goodwill amortization	-	-	39(a)
Add back: Amortization for intangibles with indefinite lives	-	-	8(b)
Adjusted Net Income (Loss)	<u>\$110</u>	<u>\$(519)</u>	<u>\$1,018</u>

Earnings (Loss) Per Share (Basic and Dilutive)

	Year Ended December 31,		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
Reported Earnings (Loss) per Share	\$0.29	\$(1.57)	\$3.01
Add back: Goodwill amortization	-	-	0.12(c)
Add back: Amortization for intangibles with indefinite lives	-	-	0.02(b)
Adjusted Earnings (Loss) per Share	<u>\$0.29</u>	<u>\$(1.57)</u>	<u>\$3.15</u>

(a) This amount includes \$34 million in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.

(b) The amounts shown for 2001 relate to CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.

(c) This amount includes \$0.10 in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are \$34 million at December 31, 2003 and \$37 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

	Amortization Life (in years)	December 31, 2003		December 31, 2002	
		Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
		(in millions)		(in millions)	
Software and customer list (a)	2	\$-	\$-	\$0.5	\$0.2
Software acquired (b)	3	0.5	0.3	0.5	-
Patent	5	0.1	-	0.1	-
Easements	10	2.2	0.3	-	-
Trade name and administration of contracts	7	2.4	0.9	2.4	0.6
Purchased technology	10	10.9	2.2	10.3	1.0
Advanced royalties	10	<u>29.4</u>	<u>7.7</u>	<u>29.4</u>	<u>4.7</u>
Total		<u>\$45.5</u>	<u>\$11.4</u>	<u>\$43.2</u>	<u>\$6.5</u>

(a) This asset was disposed of in the second quarter of 2003.

(b) This asset relates to U.K. Generation Plants and is included in Assets Held for Sale on our Consolidated Balance Sheets.

Amortization of intangible assets was \$5 million and \$4 million for the twelve months ended December 31, 2003 and 2002, respectively. Our estimated aggregate amortization expense is \$5 million for each year 2004 through 2007, \$4 million for 2008 through 2010 and \$3 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed \$3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately \$400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliations

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was \$27.5 million including interest. During the reconciliation period, TNC incurred \$293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition

begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was \$0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of \$13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of \$10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was \$6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was \$63.5 million including interest. During the reconciliation period, TCC incurred \$1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of \$81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow \$140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a \$2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred \$435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than \$30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of \$8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of the deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the

termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel (OPC) 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. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately \$2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately \$11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by \$2 million or 2.5% and increase its retail energy delivery rates by \$69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested \$67 million rate increase. The recommendations range from a decrease in existing rates of approximately \$100 million to an increase in TCC's current rates of approximately \$27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of

approximately \$51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

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 their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a \$4 million favorable adjustment recorded in December 2003.

Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately \$21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

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

PSO Rate Review

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are \$36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power

PSO had a \$44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the \$44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of \$42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. 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 will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Virginia Fuel Factor Filing

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by \$36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid \$59 million to AEP. As a result of the contract termination, AEP reversed \$69 million of unrealized mark-to-market gains previously recorded, resulting in a \$10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. 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 requested a rehearing which the FERC 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.

RTO Formation/Integration Costs

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately \$28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at \$24 million for the entire PJM integration project). Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately \$98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately \$13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set for public hearing before an ALJ several issues. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint

filing. The orders directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November orders have been appealed by a number of parties. The AEP East companies received approximately \$150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	<u>December 31,</u>		<u>Future</u>
	<u>2003</u>	<u>2002</u>	<u>Recovery/</u>
	<u>(in millions)</u>		<u>Refund Period</u>
Regulatory Assets:			
Income Tax-related Regulatory Assets, Net	\$728	\$639	Various Periods (a)
Transition Regulatory Assets	529	743	Up to 5 Years (a)
Regulatory Assets Designated for Securitization	1,253	331	(b)
Texas Wholesale Capacity Auction True-Up	480	262	(c)
Unamortized Loss on Reacquired Debt	116	83	Up to 40 Years (d)
Cook Nuclear Plant Restart Costs	-	40	N/A
Cook Nuclear Plant Refueling Outage Levelization	57	30	(e)
Deferred Fuel Costs	24	121	1 Year (a)
CSW Merger Costs	23	32	Up to 5 Years (a)
Deferred Fuel Costs (TNC)	27	27	(c)
DOE Decontamination and Decommissioning Assessment	21	26	Up to 5 Years (a)
Other	<u>290</u>	<u>354</u>	Various Periods (f)
Total Regulatory Assets	<u>\$3,548</u>	<u>\$2,688</u>	
Regulatory Liabilities:			
Asset Removal Costs	\$1,233	\$-	(h)
Deferred Investment Tax Credits	422	455	Up to 26 Years (a)
Excess ARO for Nuclear Decommissioning Liability	216	-	(g)
Deferred Over-Recovered Fuel Costs (TCC)	69	69	(c)
Deferred Over-Recovered Fuel Costs	63	21	(a)
Texas Retail Clawback	57	66	(c)
Other	<u>199</u>	<u>328</u>	Various Periods (f)
Total Regulatory Liabilities	<u>\$2,259</u>	<u>\$939</u>	

(a) Amount does not earn a return.

(b) Will be included in TCC's PUCT 2004 true-up proceeding and is designated for possible securitization during 2005.

(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment 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) These regulatory assets and liabilities include items both earning and not earning a return.

(g) Amounts are accrued monthly and will be paid when the nuclear plant is decommissioned. This also earns a return.

(h) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Deferred Over-Recovered Fuel Costs and Texas 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 complete discussion of our plans 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 Cook Plant related outage restart costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were \$40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately \$37 million in 2003 and \$38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 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:

<u>State/Company</u>	<u>Ratemaking Provisions</u>
Texas – SWEPCo, TCC, TNC	\$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	\$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of \$6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately \$14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately \$28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately \$28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of \$6 million over 5 years. No base rate increase before June 15, 2003
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be \$18 million over 8 years. Base rate cap until June 2005.

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

See Note 7, “Commitments and Contingencies” for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events related to customer choice and industry restructuring.

OHIO RESTRUCTURING

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a \$25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can 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 is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive 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. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate 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. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs that are 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. The February 2004 filing provides for the continued deferral of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, we have incurred \$66 million and deferred \$26 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future 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.

TEXAS RESTRUCTURING

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all 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 Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated

their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize \$1.27 billion of its retail generation-related regulatory assets and \$47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to \$797 million of securitization bonds (\$949 million of generation-related regulatory assets and \$33 million of qualified refinancing costs offset by \$185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's 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. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for \$43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets, including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not

securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklahoma sale and the bid information for the remaining generation, we recorded an impairment of generating assets of \$938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a \$480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the \$480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at \$6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a \$205 million over-recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were \$3 million for SWEPCo, \$47 million for TCC and \$19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory liability had

been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were \$5 million for TCC, \$3 million for TNC and \$1 million for SWEPCo.

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 has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its 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 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. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately \$9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback regulatory liability was \$57 million.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

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 rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 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.

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. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area

allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs 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 relate to costs that were incurred at our generating units over a 20-year period.

Under the Clean Air Act, 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 Clean Air Act 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 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.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-

routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is “routine maintenance, repair, or replacement” and on whether or not a “significant net emissions increase” results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is “routine within the relevant source category” in determining if it is “routine.” Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged Clean Air Act violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines “routine maintenance repair and replacement” to include “functionally equivalent equipment replacement.” Under the new final rule, replacement of a component within an integrated industrial operation (defined as a “process unit”) with a new component that is identical or functionally equivalent will be deemed to be a “routine replacement” if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

We are unable to estimate the loss or range of loss related to the contingent liability 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, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would 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.

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. 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 and TCC are 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 \$10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance 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 \$10 million. As a result, I&M could be assessed \$202 million per nuclear incident payable in annual installments of \$20 million. TCC could be assessed \$50 million per nuclear incident payable in annual installments of \$5 million as its share of a STPNOC assessment. 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 and TCC are also obligated for assessments of up to \$6 million and \$2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of \$1.8 billion each. I&M and STPNOC jointly purchase \$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 and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to \$43 million for I&M and \$2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of \$226 million for fuel consumed prior to April 7, 1983 at 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, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, 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 Cook Plant ranges from \$821 million to \$1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. 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 and deposited in the external fund was \$27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be \$289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of \$8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional \$12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on the Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2004-2006 for consolidated domestic and foreign operations are estimated to be \$5.8 billion including amounts for proposed environmental rules.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

The AEP System has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

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 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 recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to 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 non-conforming.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the “creation of protocols” was not subject to arbitration, but did not rule upon the merits of TEM’s claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately \$17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

See further discussion in Notes 10 and 16.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be “physically interconnected” and confined to a “single area or region.”

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies’ systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met 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 appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

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

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 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. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL's exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks 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 banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA's breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. 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 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 will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately \$93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of \$53 million (\$34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. 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.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent "round trip" trades or false reporting of energy prices. The plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. The Court has appointed a lead plaintiff who has filed a Consolidated Amended Complaint. We have filed a Motion to Dismiss the Consolidated Amended Complaint. The Motion has been briefed by the parties. Also, in the first quarter of 2003, a lawsuit making essentially the same allegations and demands was filed in state Common Pleas Court, Columbus, Ohio against AEP, certain executives, members of the Board of Directors and our independent auditor. We removed this case to federal District Court in Columbus and the Court has denied plaintiff's motion to remand the case to state court. We have moved to consolidate this case with the other pending cases. We intend to continue to vigorously defend against these actions.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. These cases have been stayed pending the outcome of our Motion to Dismiss the Consolidated Amended Complaint in the federal securities lawsuits. If these cases do proceed, we intend to vigorously defend against them. Also, 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. The parties have fully briefed this Motion. We intend to continue to vigorously defend against these claims.

California 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. This case is in the initial pleading stage and all defendants have filed motions to dismiss. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. In November 2003, Texas-Ohio Energy, Inc. filed a lawsuit in the United States District Court for the Eastern District of California alleging that AEP and a large number of other energy companies conspired to manipulate natural gas prices in California in violation of federal and state antitrust and unfair competition laws. Certain of the other defendants in this case have filed a Notice of Potential Tag-Along Action with the Judicial Panel on Multi-District Litigation seeking to have this case transferred to the United States District Court for the District of Nevada where there are a number of other cases now pending that assert claims regarding the alleged manipulation of energy markets in California. None of the AEP companies is a party to these other pending cases. Once venue for the Texas-Ohio Energy, Inc. case is determined, we plan to move to dismiss the complaint and otherwise vigorously defend against these claims. In February 2004, two individuals on behalf of themselves and two businesses they own and another individual filed an action in state court in San Diego County, California against a large number of energy companies including AEPES. This action alleges violations of state antitrust and unfair competition laws based on alleged manipulation of gas price indices. This case is in the initial pleading states. We plan to vigorously defend against these claims.

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. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We plan to move to dismiss the complaint and otherwise vigorously defend 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 AEP subsidiaries, certain unaffiliated energy companies and ERCOT. The action alleges 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 alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over \$500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately \$34 million. 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 and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately \$68 million. We are claiming that BOM owes us at least \$45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In October 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding resulted from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries by AEP. Consequently, both parties claimed default and terminated all outstanding natural gas and electric power trading deals among the various Williams and AEP affiliates. Williams claimed that we owed approximately \$130 million in connection with the termination and liquidation of all trading deals. Williams and AEP settled the dispute and we paid \$90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter did not have a material impact on results of operations or financial condition.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately \$22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement and we paid approximately \$11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows 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 has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges 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 seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that

the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs 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 LOCs were issued by us in the ordinary course of business. At December 31, 2003, the maximum future payments for all the LOCs are approximately \$227 million with maturities ranging from January 2004 to January 2011. Included in these amounts is TCC's LOC of approximately \$43 million with a maturity date of November 3, 2005. As the parent of all these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

We have guaranteed 50% of the principal and interest payments as well as 100% of a Power Purchase Agreement (PPA) of Fort Lupton, an IPP of which we are a 50% owner. In the event Fort Lupton does not make the required debt payments, we have a maximum future payment exposure of approximately \$7 million, which expires May 2008.

In the event Fort Lupton is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately \$15 million, which expires June 2019.

We have guaranteed 50% of a security deposit for gas transmission as well as 50% of a Power Purchase Agreement (PPA) of Orange Cogeneration (Orange), an IPP of which we are a 50% owner. In the event Orange fails to make payments in accordance with agreements for gas transmission, we have a maximum future payment exposure of approximately \$1 million, which expires June 2023. In the event Orange is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately \$1 million, which expires June 2016.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration (Sweeny), an IPP of which CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of a financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately \$4 million, which expires June 2020.

AEP Utilities

AEP Utilities guaranteed 50% of the required debt service reserve for Polk Power Partners, an IPP of which CSW Energy owns 50%. In the event that Polk Power does not make the required debt payments, AEP Utilities has a maximum future payment exposure of approximately \$5 million, which expires July 2010.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements,

SWEPCo's total future maximum payment exposure is approximately \$58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide 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, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately \$36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine (\$78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's 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.

INDEMNIFICATIONS AND OTHER GUARANTEES

We entered into several types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 we entered into several sale agreements discussed in Note 10. These sale agreements include indemnifications with a maximum exposure of approximately \$57 million. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

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, 2003, the maximum potential loss for these lease agreements was approximately \$28 million assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in our business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling \$75.4 million pre-tax was recorded in the fourth quarter of 2002. Of this amount, we paid \$9.5 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Maintenance and Other Operation expense on our Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2002

Acquisition of Nordic Trading (Investments – UK Operations segment)

In January 2002 we acquired the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in our Consolidated Statements of Operations from the date of acquisition. Subsequently in the fourth quarter of 2002, a decision was made to exit this non-core European trading business. The sale of Nordic Trading in the second quarter of 2003 is discussed in the "Dispositions" section of this note.

Acquisition of USTI (Investments – Other segment)

In January 2002, we acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for \$12.5 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both our affiliates and external customers. Results of operations are included in our Consolidated Statements of Operations from the date of acquisition.

2001

Houston Pipe Line Company (Investments – Gas Operations segment)

On June 1, 2001, through a wholly-owned subsidiary, we purchased Houston Pipe Line Company and Lodisco LLC for \$727 million from Enron. The acquired assets include 4,200 miles of gas pipeline, a 30-year prepaid lease of a gas storage facility and certain gas marketing contracts. The purchase method of accounting was used to record the acquisition. During 2003 we recorded impairment and other losses for HPL and related gas operations of \$315 million (\$228 million net of tax).

U.K. Generation Plants (Investments – UK Operations segment)

In December 2001, we acquired 4,000 megawatts of coal-fired generation from Fiddler's Ferry, a four-unit, 2,000 MW station on the River Mersey in northwest England, and Ferrybridge, a four-unit, 2,000 MW station on the River Aire in northeast England and related coal stocks. These assets were acquired for a cash payment of \$942.3 million and the assumption of certain liabilities. During 2003 these assets became held-for-sale and we reported the operations as discontinued. See U.K. Generation Plants in the "Discontinued Operations" section of this note for further information.

Other Acquisitions (Various segments)

We also purchased the following assets or acquired the following businesses from July 2001 through December 2001:

- Dolet Hills mining operations were purchased by SWEPCo, an AEP subsidiary, and SWEPCo also assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana.
- Quaker Coal Company as part of a bankruptcy proceeding settlement was acquired, including certain liabilities.

The acquisition includes property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. We continue to operate the mines and facilities. See AEP Coal in the “Assets Held for Sale” section of this note for further information on our decision to dispose of this investment.

- MEMCO Barge Line was acquired adding 1,200 hopper barges and 30 towboats to AEP’s existing barging fleet. MEMCO added major barging operations on the Mississippi and Ohio rivers to AEP’s barging operations on the Ohio and Kanawha rivers.
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale was acquired by converting a total of \$66 million on an existing loan and accrued interest on that loan into Caiua equity. See Grupo Rede Investment in the “Dispositions” section of this note for further information.
- Indian Mesa Wind Project (referred to as “Desert Sky”) consisting of 160 MW of wind generation located near Fort Stockton, Texas was purchased.
- Enron’s London-based international coal trading group was acquired by purchasing existing contracts and hiring key staff.

Management recorded the assets acquired and liabilities assumed at their estimated fair values based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

C3 Communications (Investments – Other segment)

In February 2003, C3 Communications sold the majority of its assets for a sales price of \$7.25 million. We provided for an \$82 million pre-tax (\$53 million after-tax) asset impairment in December 2002 and the effect of the sale on 2003 results of operations was not significant. The impairment is classified in Asset Impairments and Other Related Changes in our Consolidated Statements of Operations. See “Assets Held for Sale” section of this note for information on assets and liabilities held for sale at December 31, 2002 related to our “telecommunications” businesses.

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 L.P. and Mutual Energy WTU L.P. 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 \$145.5 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a net gain totaling \$83.7 million after-tax (\$129 million pre-tax) in Other Income 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 2003 related to these sharing agreements. Under the Texas 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 are being amortized over the two-year term of the back office service agreement.

In February 2003, we completed the sale of MESC for \$30.4 million dollars and realized a pre-tax gain of approximately \$39 million, which included the recognition of the remaining balance of the original \$30 million prepayment (\$27 million), as no further service obligations existed for MESC.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for \$38 million and recorded a pre-tax loss of \$3.9 million in the first quarter of 2003 based upon final terms of the sale agreement. We had provided for a \$7.1 million pre-tax charge in the fourth quarter 2002 based on an estimated sales price (\$3.2 million asset impairment charge and \$3.9 million lease prepayment penalty). The impairment loss is included in Investment Value Losses in our Consolidated Statements of Operations. 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. See the "Assets Held for Sale" section of this Note for assets and liabilities held for sale as of December 31, 2002.

AEP Gas Power Systems (Investments – Other segment)

In 2001, we acquired a 75% interest in a startup company, seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. In January 2003, AEP Gas Power Systems, LLC sold its assets. We recognized a goodwill impairment loss of \$12.3 million pre-tax in the first quarter of 2002 due to technological and operational problems (also see Note 3). The impairment loss was recorded in Investment Value Losses on our Consolidated Statements of Operations. The fair values of the remaining assets and liabilities as of December 31, 2002 were excluded from held for sale on our Consolidated Balance Sheets as the impact was not significant. The effect of the asset sale on the first quarter 2003 results of operations was not significant.

Newgulf Facility (Investments – Other segment)

In 1995, we purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002, we began negotiations with a likely buyer of the facility. We estimated a pre-tax loss on sale of \$11.8 million based on the indicative bid. This loss was recorded as Asset Impairments and Other Related Charges on our Consolidated Statements of Operations during the fourth quarter 2002. Newgulf's Property, Plant and Equipment, net of accumulated depreciation, was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. During the second quarter of 2003 we completed the sale of Newgulf and the impact on earnings in 2003 was not significant.

Nordic Trading (Investments – UK Operations segment)

In October 2002 we announced that our ongoing energy trading operations would be centered around our generation assets. As a result, we took steps to exit our coal, gas and electricity trading activities in Europe, except for those activities predominantly related to our U.K. generation operations. The Nordic Trading business acquired earlier in 2002 was made available for sale to potential buyers later in 2002. The estimated pre-tax loss on disposal recorded in 2002 of \$5.3 million, consisted of impairment of goodwill of \$4.0 million and impairment of assets of \$1.3 million. The estimated loss of \$5.3 million is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. Management's determination of a zero fair value was based on discussions with a potential buyer. The assets and liabilities of Nordic Trading have been classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. The transfer of the Nordic Trading business, including the trading portfolio, to new owners was completed during the second quarter of 2003 and the impact on earnings during the second quarter of 2003 was not significant.

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 pre-tax loss on sale of \$218.7 million pre-tax (\$142 million after-tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in Discontinued Operations in our Consolidated Statements of Operations during the fourth quarter 2002.

We completed the sale of Eastex during the third quarter of 2003 and the effect of the sale on third quarter 2003 results of operations was not significant. The results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144 for all years presented. The assets and liabilities of Eastex were reclassified on the Consolidated Balance Sheets from Assets Held for Sale and Liabilities Held for Sale to Discontinued Operations at December 31, 2002. See “Discontinued Operations” section of this note for additional information.

Grupo Rede Investment (Investments – Other segment)

In December 2002, we recorded an other than temporary impairment totaling \$141.0 million (\$217.0 million net of federal income tax benefit of \$76.0 million) of our 44% equity investment in Vale and our 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This amount is included in Investment Value Losses on our Consolidated Statements of Operations.

In December 2003 we transferred our share and investment in Vale to Grupo Rede for \$1 million. The effect of the transfer on fourth quarter results of operations was not significant.

Excess Equipment (Investments – Other segment)

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We had been unsuccessful in finding potential buyers of the unit due to an over-supply of generation equipment available for sale during 2002. An estimated pre-tax loss on disposal of \$23.9 million was recorded in December 2002, based on market prices of similar equipment. The loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Other asset of \$12 million in 2002 was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002.

We completed the sale of the surplus gas turbine generator in November 2003. The proceeds from the sale were \$8.7 million. A pre-tax loss of \$1.8 million was recorded in the fourth quarter of 2003.

Ft. Davis Wind Farm (Investments – Other segment)

In the 1990's, we developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 our engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of \$4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

2002

SEEBOARD (Investments – Other segment)

On June 18, 2002, through a wholly-owned subsidiary, we entered into an agreement, subject to European Union (EU) approval, to sell our consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. We received approximately \$941 million in net cash from the sale, subject to a working capital true up, and the buyer assumed SEEBOARD debt of approximately \$1.12 billion, resulting in a net loss of \$345 million at June 30, 2002. The results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A net loss of \$22 million pre-tax (\$14 million after-tax) was classified as Discontinued Operations in the second quarter of 2002. The remaining \$323 million of the net loss has been classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A \$59 million pre-tax (\$38 million after-tax) reduction of the net loss was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The net total loss recognized on the disposal of SEEBOARD was \$286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt. See “Discontinued Operations” section for the total revenues and pretax profit (loss) of the discontinued operations of SEEBOARD.

CitiPower (Investments – Other segment)

On July 19, 2002, through a wholly owned subsidiary, we entered into an agreement to sell CitiPower, a retail electricity and gas supply and distribution subsidiary in Australia. We completed the sale on August 30, 2002 and received net cash of approximately \$175 million and the buyer assumed CitiPower debt of approximately \$674 million. We recorded a pre-tax charge totaling \$192 million (\$125 million after-tax) as of June 30, 2002. The charge included a pre-tax impairment loss of \$151 million (\$98 million after-tax) on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining \$41 million pre-tax (\$27 million after-tax) of net loss was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and was recorded as a Cumulative Effect of Accounting Change retroactive to January 1, 2002.

The loss on the sale of CitiPower increased \$37 million pre-tax (\$24 million after-tax) to \$229 million pre-tax (\$149 million after-tax; \$122 million plus \$27 million of cumulative effect) in the second half of 2002 based on actual closing amounts and exchange rates. See the “Discontinued Operations” section of this note for the total revenues and pretax profit (loss) of the discontinued operations of CitiPower.

2001

In March 2001, CSWE, a subsidiary company, completed the sale of Frontera, a generating plant that the FERC required to be divested in connection with the merger of AEP and CSW. The sale proceeds were \$265 million and resulted in an after-tax gain of \$46 million (\$73 million pre-tax).

In July 2001, through a wholly-owned subsidiary, we sold our 50% interest in a 120-megawatt generating plant located in Mexico. The sale resulted in an after tax gain of approximately \$11 million.

In July 2001, we sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on our results of operations and cash flows.

In December 2001, we completed the sale of our ownership interests in the Virginia and West Virginia PCS (Personal Communications Services) Alliances for stock, resulting in an after tax gain of approximately \$7 million. Subsequently during 2002, due to decreasing market value of the shares received from the sale, we reduced the value of them to zero.

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 and Liabilities Held for Sale until the time that they are sold. At the time they are sold they are reclassified to Assets and Liabilities of Discontinued Operations on the Consolidated Balance Sheets for all periods presented. Assets and liabilities that are held for sale, but do not qualify as a discontinued operations are reflected as Assets and Liabilities Held for Sale both while they are held for sale and after they have been sold, for all periods presented.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2003, 2002 and 2001. Results of operations of these businesses have been reclassified as shown in the following table:

	<u>SEE- BOARD</u>	<u>CitiPower</u>	<u>Eastex</u>	<u>Pushan Power Plant</u>	<u>LIG</u>	<u>U.K. Generation Plants</u>	<u>Total</u>
2003 Revenue	\$-	\$-	\$58	\$60	\$653	\$125	\$896
2003 Pretax Profit (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss) After Tax	16	(13)	(14)	4	(91)	(507)	(605)
2002 Revenue	694	204	73	57	507	251	1,786
2002 Pretax Profit (Loss)	180	(190)	(239)	(13)	14	(579)	(827)
2002 Earnings (Loss) After Tax	96	(123)	(156)	(7)	8	(472)	(654)
2001 Revenue	1,451	350	-	57	525	26	2,409
2001 Pretax Profit (Loss)	104	(4)	1	8	(6)	(48)	55
2001 Earnings (Loss) After Tax	88	(6)	-	4	(4)	(41)	41

Assets and liabilities of discontinued operations have been reclassified as follows:

	<u>Eastex</u> (in millions)
<u>As of December 31, 2002</u>	
Current Assets	<u>\$15</u>
Total Assets of Discontinued Operations	<u>\$15</u>
Current Liabilities	\$8
Deferred Credits and Other	<u>4</u>
Total Liabilities of Discontinued Operations	<u>\$12</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 and a purchase and sale agreement was signed in the fourth quarter of 2003. We expect to close on this transaction by mid 2004. An estimated pre-tax loss on disposal of \$20 million pre-tax (\$13 million after-tax) was recorded in December 2002, based on an indicative price expression. The estimated pre-tax loss on disposal is classified in Discontinued Operations in our Consolidated Statements of Operations.

Results of operations of Pushan have been reclassified as Discontinued Operations. The assets and liabilities of Pushan have been classified on our Consolidated Balance Sheets as held for sale. We have classified the assets and liabilities as held for sale for longer than 12 months, which is longer than originally expected, due to several unusual circumstances including the SARS outbreak and governmental delays.

Louisiana Intrastate Gas (LIG) (Investments – Gas Operations segment)

After announcing during 2003 that we would be divesting our non-core assets we began actively marketing LIG with the help of an investment advisor. After receiving and analyzing initial bids during the fourth quarter 2003 we recorded a \$133.9 million pre-tax (\$99 million after-tax) impairment loss; of this loss, \$128.9 million pre-tax relates to the impairment of goodwill and \$5 million pre-tax relates to other charges. In February 2004, we signed a definitive agreement to sell the pipeline portion of LIG. We anticipate the sale will be completed during the second quarter of 2004 and that the impact on results of operations in 2004 will not be significant. The assets and liabilities of LIG are classified as held for sale on our Consolidated Balance Sheets and the results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations.

U.K. Generation Plants (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 \$942.3 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 pre-tax impairment loss of \$548.7 million (\$414 million after-tax). This impairment loss is included in 2002 Discontinued Operations on our Consolidated Statements of Operations.

Management has retained an investment advisor to assist in determining the best methodology to exit the U.K. business. An information memorandum was distributed for the sale of our U.K. Generation and based on current information we recorded a \$577 million pre-tax charge (\$375 after-tax), including asset impairments of \$420.7 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional charges of \$156.7 million pre-tax were also recorded in December 2003 including \$122.2 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income that has been reclassified into earnings as a result of management's determination that the hedged event is no longer probable of occurring and \$34.5 million related to a first quarter 2004 sale of certain power contracts. The assets and liabilities of U.K. Generation have been classified as held for sale on our Consolidated Balance Sheets and the results of operations are included in Discontinued Operations on our Consolidated Statements of Operations. We anticipate the sale of the U.K. Generation plants during 2004.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2003, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling \$1.4 billion [consisting of approximately \$650 million related to Asset Impairments (\$610 million) and Other Related Charges (\$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 in the Consolidated Statements of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit non-core businesses and other factors.

In 2002, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling \$1.7 billion (consisting of approximately \$318 million related to Asset Impairments, \$321 million related to Investment Value Losses, \$938 million related to Discontinued Operations and \$88 million related to charges recorded in other lines within the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional goodwill impairment loss from adoption of SFAS 142 (see Notes 2 and 3).

The categories of impairments include:

	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
<u>Asset Impairments and Other Related Charges (Pre-tax)</u>			
AEP Coal	\$67	\$60	\$-
HPL and Other	315	-	-
Power Generation Facility	258	-	-
Blackhawk Coal Company	10	-	-
Ft. Davis Wind Farm	-	5	-
Texas Plants	-	38	-
Newgulf Facility	-	12	-
Excess Equipment	-	24	-
Nordic Trading	-	5	-
Excess Real Estate	-	16	-
Telecommunications – AEPC/C3	-	158	-
Total	<u>\$650</u>	<u>\$318</u>	<u>\$-</u>
<u>Investment Value Losses (Pre-tax)</u>			
Independent Power Producers	\$70	\$-	\$-
Water Heater Assets	-	3	-
South Coast Power Investment	-	63	-
Telecommunications – AFN	-	14	-
AEP Gas Power Systems	-	12	-
Grupo Rede Investment – Vale	-	217	-
Technology Investments	-	12	-
Total	<u>\$70</u>	<u>\$321</u>	<u>\$-</u>
<u>“Impairments and Other Related Charges” and “Operations” Included in Discontinued Operations (After-tax)</u>			
Impairments and Other Related Charges:			
U.K. Generation Plants	\$(375)	\$(414)	\$-
Louisiana Intrastate Gas	(99)	-	-
CitiPower	-	(122)	-
Eastex	-	(142)	-
SEEBOARD	-	24	-
Pushan	-	(13)	-
Total*	<u>(474)</u>	<u>(667)</u>	<u>-</u>
Operations:			
U.K. Generation Plants	(132)	(58)	(41)
Louisiana Intrastate Gas	8	8	(4)
CitiPower	(13)	(1)	(6)
Eastex	(14)	(14)	-
SEEBOARD	16	72	88
Pushan	4	6	4
Total	<u>(131)</u>	<u>13</u>	<u>41</u>
Total Discontinued Operations	<u>\$(605)</u>	<u>\$(654)</u>	<u>\$41</u>

* See the “Dispositions” and “Discontinued Operations” sections of this note for the pre-tax impairment figures.

ASSETS HELD FOR SALE

Telecommunications (Investments – Other segment)

We developed businesses to provide telecommunication services to businesses and other telecommunication companies through broadband fiber optic networks. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, the AEP Board approved in December 2002 a plan to cease operations of these businesses. We took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002.

We completed the sale of substantially all the assets of C3 in the first quarter of 2003 as discussed in the “Dispositions” section of this note. AFN closed on the sale of substantially all of its assets in January 2004 with no significant additional effect on results of operations in 2004. The sale of remaining telecommunication assets is proceeding.

An estimated pre-tax impairment loss of \$158.5 million (\$76.3 million related to AEPC and \$82.2 million related to C3) was recorded in December 2002 and is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations. An estimated pre-tax loss in value of the investment in AFN of \$13.8 million was recorded in December 2002 and is classified in Investment Value Losses in our Consolidated Statements of Operations. The estimated losses were based on indicative bids by potential buyers. Property, Plant and Equipment, net of accumulated depreciation, of the telecommunication businesses have been classified on our Consolidated Balance Sheets as held for sale in 2002.

AEP Coal (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.” 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 is 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 pre-tax impairment loss of \$59.9 million including a goodwill impairment of \$3.6 million as discussed in Note 3. This impairment loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In 2003, as a result of management’s decision to exit our non-core businesses, we retained an advisor to facilitate the sale of AEP Coal. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a \$66.6 million pre-tax (\$43.6 million after-tax) charge comprised of a \$29.4 million asset impairment, a \$25.2 million charge related to accelerated remediation cost accruals and \$12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses were included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The assets and liabilities of AEP Coal that are held for sale have been included in Assets and Liabilities Held for Sale in our Consolidated Balance Sheets at December 31, 2003 and 2002.

Texas Plants (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 a 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, a write-down of utility assets of approximately \$34.2 million (pre-tax) was recorded in Asset Impairments and Other Related Charges expense during the third quarter 2002 on our Consolidated Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately \$95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in our Consolidated Balance Sheets.

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 asset impairment charge to Asset Impairments and Other Related Charges expense of \$3.9 million (pre-tax) in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of \$2.6 million (\$1.2 million in Fuel for Electric Generation and \$1.4 million in Maintenance and Other Operation). Similarly, TCC recorded an additional asset impairment write-down of \$6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets in the fourth quarter of 2002. TCC also recorded related inventory write-downs of \$14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of \$38.1 million pre-tax in 2002 (all related to TNC) is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

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 RMR status. During the fourth quarter of 2003, after receiving 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. In accordance with Texas legislation, the \$938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6, "Customer Choice and Industry Restructuring," for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

	<u>Pushan Power Plant</u>	<u>U.K. Generation Plants</u>	<u>AEP Coal</u>	<u>Texas Plants</u>	<u>LIG</u>	<u>Total</u>
<u>December 31, 2003</u>				(in millions)		
Assets:						
Current Assets	\$24	\$1,245	\$6	\$57	\$50	\$1,382
Property, Plant and Equipment, Net	142	99	13	797	171	1,222
Regulatory Assets	-	-	-	49	-	49
Spent Nuclear Fuel and Decommissioning						
Trusts	-	-	-	125	-	125
Goodwill	-	-	-	-	15	15
Long-term Risk Management Assets	-	274	-	-	-	274
Other	-	6	-	-	9	15
Total Assets Held for Sale	<u>\$166</u>	<u>\$1,624</u>	<u>\$19</u>	<u>\$1,028</u>	<u>\$245</u>	<u>\$3,082</u>
Liabilities:						
Current Liabilities	\$26	\$988	\$-	\$-	\$61	\$1,075
Long-term Debt	20	-	-	-	-	20
Long-term Risk Management Liabilities	-	435	-	-	-	435
Regulatory Liabilities and Deferred						
Investment Tax Credits	-	-	-	9	-	9
Asset Retirement Obligations and						
Nuclear Decommissioning Trusts	-	29	-	219	-	248
Employee Benefits and Pension Obligations	-	12	-	-	-	12
Deferred Credits and Other	57	-	14	-	6	77
Total Liabilities Held for Sale	<u>\$103</u>	<u>\$1,464</u>	<u>\$14</u>	<u>\$228</u>	<u>\$67</u>	<u>\$1,876</u>

	Pushan Power Plant	U.K. Generation Plants	AEP Coal	Texas Plants	LIG (in millions)	Tele- Commun- ications	Nordic Trading	Newgulf Facility	Excess Equipment	Water Heater Program	Total
December 31, 2002											
Assets:											
Current Assets	\$19	\$571	\$4	\$70	\$62	\$-	\$35	\$-	\$-	\$1	\$762
Property, Plant and Equipment, Net	132	445	38	1,647	169	6	-	6	-	38	2,481
Spent Nuclear Fuel and Decommissioning Trusts	-	-	-	98	-	-	-	-	-	-	98
Goodwill	-	11	-	-	144	-	-	-	-	-	155
Long-term Risk Management Assets	-	61	-	-	-	-	5	-	-	-	66
Other	-	22	-	-	-	-	5	-	12	-	39
Total Assets											
Held for Sale	<u>\$151</u>	<u>\$1,110</u>	<u>\$42</u>	<u>\$1,815</u>	<u>\$375</u>	<u>\$6</u>	<u>\$45</u>	<u>\$6</u>	<u>\$12</u>	<u>\$39</u>	<u>\$3,601</u>
Liabilities:											
Current Liabilities	\$28	\$992	\$-	\$-	\$53	\$-	\$48	\$-	\$-	\$-	\$1,121
Long-term Debt	25	-	-	-	-	-	-	-	-	-	25
Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Long-term Risk Management Liabilities	-	39	-	-	7	-	3	-	-	-	49
Deferred Credits and Other	26	24	15	9	10	-	-	-	-	-	84
Total Liabilities											
Held for Sale	<u>\$79</u>	<u>\$1,055</u>	<u>\$15</u>	<u>\$9</u>	<u>\$70</u>	<u>\$-</u>	<u>\$51</u>	<u>\$-</u>	<u>\$-</u>	<u>\$-</u>	<u>\$1,279</u>

ASSETS HELD AND USED

In 2003 and 2002, we recorded the following impairments related to assets (including Goodwill) held and used to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations as discussed below:

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, TX obtained through our merger with CSW. Sale of the facility was projected by the second quarter 2003 and an estimated pre-tax loss on disposal of \$15.7 million was recorded in 2002, based on the option sale price. The estimated loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Property asset of \$18 million in 2002 and \$36 million in 2001 was previously classified on our Consolidated Balance Sheets as held for sale.

The sale of this office building was not completed by the end of 2003 and as a result the building no longer qualifies for held for sale status. In accordance with SFAS 144 the building will be moved to held and used status for all periods presented as of December 31, 2003. In December 2003 we recorded an additional pre-tax impairment of \$6 million based on bids received to date. The impairment is recorded in Maintenance and Other Operation on our Consolidated Statements of Operations. The building will continue to be actively marketed.

HPL and Other (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 non-core assets, which includes the assets within our Investments-Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted after-tax cash flow analysis of the fair value of HPL, we recorded an impairment of \$300 million pre-tax (\$218 million after-tax), with \$150 million pre-tax related to goodwill, reflecting management's decision not to operate HPL as a

major trading hub and market indicators supported by the LIG bid process. 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 Note 7) and an after-tax risk free discount rate of 3.3% over the remaining life of the assets.

We also recorded a \$15 million pre-tax charge (\$10 million after-tax) in the fourth quarter 2003 included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. 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.

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 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 \$10.4 million pre-tax charge 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 in our Consolidated Statements of Operations.

Power Generation Facility (Investments – Other segment)

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation. In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded \$496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by 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 \$258 million pre-tax impairment (\$168 million after-tax) in December 2003 on the CWIP.

See further discussion in Notes 7 and 16.

INVESTMENT VALUE AND OTHER LOSSES

In 2003 and 2002, we recorded the following declines in fair value on investments:

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. Based on indicative bids, it was determined that an other than temporary impairment existed on two of the equity investments. The impairment was the result of the measurement of fair value that was triggered by our recent decision to sell the assets. A \$70.0 million pre-tax (\$45.5 million net of tax) loss was recorded in September 2003 as a result of an other than temporary impairment of the equity interest. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations. We have received bids on the IPP investments and anticipate a final sale during the first half of 2004.

South Coast Power Investment (Investments – Other segment)

South Coast Power is a 50% owned joint venture that was formed in 1996 to build and operate a merchant closed-cycle gas turbine generator at Shoreham, U.K. South Coast Power is subject to the same adverse wholesale electric power rates described for U.K. Generation Plants above in “Discontinued Operations.” A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pre-tax other than temporary impairment of the equity interest (which included the fair value of supply contracts held by South Coast Power and accounted for in accordance with SFAS 133) in the amount of \$63.2 million. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations in 2002.

Technology Investments (Investments – Other segment)

We previously made investments totaling \$11.7 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18 was recorded. The loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations.

11. BENEFIT PLANS

In the U.S. we sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees in the U.S. 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 death benefits for retired employees in the U.S.

We also have a foreign pension plan for employees of AEP Energy Services U.K. Generation Limited (Genco) in the U.K. The Genco pension plan had \$7 million of accumulated benefit obligations in excess of plan assets at December 31, 2002. The plan was in an overfunded position at December 31, 2003.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Change in Benefit Obligation:	(in millions)			
Obligation at January 1	\$3,583	\$3,292	\$1,877	\$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	<u>(299)</u>	<u>(278)</u>	<u>(92)</u>	<u>(81)</u>
Obligation at December 31	<u>\$3,688</u>	<u>\$3,583</u>	<u>\$2,163</u>	<u>\$1,877</u>
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	\$2,795	\$3,438	\$723	\$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	<u>(299)</u>	<u>(278)</u>	<u>(92)</u>	<u>(81)</u>
Fair Value of Plan Assets at December, 31	<u>\$3,180</u>	<u>\$2,795</u>	<u>\$950</u>	<u>\$723</u>

Funded Status:

Funded Status at December 31	\$(508)	\$(788)	\$(1,213)	\$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	<u>\$279</u>	<u>\$212</u>	<u>\$(24)</u>	<u>\$(19)</u>

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

Accumulated Benefit Obligation:

	<u>2003</u>	<u>2002</u>
	(in millions)	
U.S. Qualified Pension Plans	\$3,549	\$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
	(in millions)			
Prepaid Benefit Costs	\$325	\$255	\$-	\$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	<u>\$279</u>	<u>\$212</u>	<u>\$(24)</u>	<u>\$(19)</u>

**Increase (Decrease) in Minimum Liability
Included in Other Comprehensive
Income (Pre-tax)**

	<u>\$(216)</u>	<u>\$894</u>	<u>N/A</u>	<u>N/A</u>
--	----------------	--------------	------------	------------

N/A = Not Applicable

The asset allocations for our U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

<u>Asset Category</u>	<u>Target Allocation</u>	<u>Percentage of Plan Assets at Yearend</u>	
	<u>2004</u>	<u>2003</u>	<u>2002</u>
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	<u>100</u>	<u>100</u>	<u>100</u>

The asset allocations for our U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

<u>Asset Category</u>	<u>Target Allocation</u>	<u>Percentage of Plan Assets at Yearend</u>	
	<u>2004</u>	<u>2003</u>	<u>2002</u>
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	<u>100</u>	<u>100</u>	<u>100</u>

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.

The value of our qualified plans' assets increased from \$2.795 billion at December 31, 2002 to \$3.180 billion at December 31, 2003. The qualified plans paid \$292 million in benefits to plan participants during 2003 (nonqualified plans paid \$7 million in benefits). The status of our plans remains in an underfunded position (plan assets are less than projected benefit obligations) of \$508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded income in Other Comprehensive Income (OCI) of \$154 million, and a reduction in the Deferred Income Tax Asset of \$76 million, offset by a reduction to Minimum Pension Liability of \$234 million and a reduction in adjustments for unrecognized costs of \$4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of our qualified plans, we expect to make cash contributions to our U.S. pension plans of approximately \$41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

<u>End of Year</u>	<u>U.S. Plans</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Projected Benefit Obligation	\$3,688	\$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

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.

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

	<u>U.S. Pension Plans</u>		<u>U.S. Other Postretirement Benefit Plans</u>	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
	(in percentages)			
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations we review the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, we determined that a decrease in our discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

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

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	<u>U.S. Pension Plans</u>	<u>U.S. Other Postretirement Benefit Plans</u>
	(in millions)	
<u>Employer Contributions</u>		
2003	\$65	\$183
2004 (expected)	41	180

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. 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:

	<u>U.S. Pension Benefits</u>	<u>U.S. Other Postretirement Benefit Plans</u>
	(in millions)	
2004	\$293	\$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts 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 following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	<u>U.S. Pension Plans</u>			<u>U.S. Other Postretirement Benefit Plans</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)					
Service Cost	\$80	\$72	\$69	\$42	\$34	\$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	<u>11</u>	<u>(10)</u>	<u>(24)</u>	<u>52</u>	<u>27</u>	<u>18</u>
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>1</u>
Net Periodic Benefit Cost (Credit) After Curtailments	<u>\$(3)</u>	<u>\$(44)</u>	<u>\$(69)</u>	<u>\$188</u>	<u>\$142</u>	<u>\$132</u>

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

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
			(in percentage)			
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as Unrelated Business Income Taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	<u>2003</u>	<u>2002</u>
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

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

	<u>1% Increase</u>	<u>1% Decrease</u>
	(in millions)	
Effect on Total Service and Interest Cost		
Components of Net Periodic Postretirement		
Health Care Benefit Cost	\$26	\$(21)
Effect on the Health Care Component of the		
Accumulated Postretirement Benefit Obligation	315	(257)

We have not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on our other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on our results of operations, cash flows and financial condition.

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. On January 1, 2003, the two major AEP Savings Plans merged into a single plan. Beginning in 2001, and continuing under the single merged plan, our contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled \$57.0 million in 2003, \$60.1 million in 2002 and \$55.6 million in 2001.

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 2003, 2002 and 2001.

12. STOCK-BASED COMPENSATION

The American Electric Power System 2000 Long-Term Incentive Plan (the Plan) authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was adopted in 2000 by the Board of Directors and shareholders.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance share units and stock options. Restricted stock units vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st for three years following the grant date. Amounts equivalent to cash dividends on the units accrue as additional units. AEP awarded 105,910 restricted stock units, including dividends, in 2003, with a weighted-average grant-date fair value of \$22.17 per unit. 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.

AEP awarded 300,000 restricted shares in January 2004, which vest over periods ranging from 1 to 8 years. Compensation cost will be recorded over the vesting period based on the market value of \$30.76 per unit on the grant date.

Performance share units are equal in value to shares of AEP common stock but are subject to an attached performance factor ranging from 0% to 200%. 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. Performance share 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 participants AEP career. Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. The compensation cost for performance share units is recorded over the vesting period and both the performance share and phantom stock unit liability is adjusted for changes in fair market value. Amounts equivalent to cash dividends on both performance share and phantom stock units accrue as additional units.

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 its policy, AEP does not record compensation expense. AEP generally grants options that have a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 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 periods 2003, 2002 and 2001 is as follows:

	<u>2003</u>		<u>2002</u>		<u>2001</u>	
	<u>Options</u> <u>(in thousands)</u>	<u>Weighted</u> <u>Average</u> <u>Exercise</u> <u>Price</u>	<u>Options</u> <u>(in thousands)</u>	<u>Weighted</u> <u>Average</u> <u>Exercise</u> <u>Price</u>	<u>Options</u> <u>(in thousands)</u>	<u>Weighted</u> <u>Average</u> <u>Exercise</u> <u>Price</u>
Outstanding at beginning of year	8,787	\$34	6,822	\$37	6,610	\$36
Granted	927	\$28	2,923	\$27	645	\$45
Exercised	(23)	\$27	(600)	\$36	(216)	\$38
Forfeited	<u>(597)</u>	\$33	<u>(358)</u>	\$41	<u>(217)</u>	\$37
Outstanding at end of year	<u>9,094</u>	\$33	<u>8,787</u>	\$34	<u>6,822</u>	\$37
Options exercisable at end of year	<u>3,909</u>	\$36	<u>2,481</u>	\$36	<u>395</u>	\$43
Weighted average exercise price of options:						
-Granted above Market Price		N/A		\$27		N/A
-Granted at Market Price		\$28		\$27		\$45

The following table summarizes information about AEP stock options outstanding at December 31, 2003:

<u>Options Outstanding</u>			
<u>Range of Exercise Prices</u>	<u>Number Outstanding</u> (in thousands)	<u>Weighted Average</u> <u>Remaining Life</u> (in years)	<u>Weighted Average</u> <u>Exercise Price</u>
\$25.73 - \$27.95	3,530	9.1	\$27.28
\$34.58 - \$41.50	5,054	6.6	\$35.74
\$43.79 - \$49.00	<u>510</u>	7.5	\$45.98
	<u>9,094</u>	7.6	\$33.03
<u>Options Exercisable</u>			
<u>Range of Exercise Prices</u>	<u>Number Outstanding</u> (in thousands)	<u>Weighted Average Exercise Price</u>	
\$25.73 - \$27.95	52	\$27.06	
\$34.58 - \$41.50	3,610	\$35.78	
\$43.79 - \$49.00	<u>247</u>	\$46.57	
	<u>3,909</u>	\$36.35	

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:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Risk Free Interest Rate	3.92%	3.53%	4.87%
Expected Life	7 years	7 years	7 years
Expected Volatility	27.57%	29.78%	28.40%
Expected Dividend Yield	4.86%	6.15%	6.05%
Weighted average fair value of options:			
-Granted above Market Price	N/A	\$4.58	N/A
-Granted at Market Price	\$5.26	\$4.37	\$8.01

13. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations

- Domestic generation of electricity for sale to retail and wholesale customers
- Domestic electricity transmission and distribution

*Investments - Gas Operations**

- Gas pipeline and storage services

*Investments - UK Operations***

- International generation of electricity for sale to wholesale customers
- Coal procurement and transportation to AEP plants and third parties

Investments – Other

- Coal mining, bulk commodity barging operations and other energy supply businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.

** UK Operations were classified as discontinued during 2003.

The tables below present segment information for the twelve months ended December 31, 2003, 2002 and 2001. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

	<u>Investments</u>				<u>All Other*</u>	<u>Reconciling Adjustments</u>	<u>Consolidated</u>
	<u>Utility Operations</u>	<u>Gas Operations</u>	<u>UK Operations</u>	<u>Other</u> (in millions)			
2003							
Revenues from:							
External Customers	\$10,871	\$3,097	\$-	\$ 577	\$-	\$ -	\$14,545
Other Operating Segments	-	192	-	96	11	(299)	-
Discontinued Operations, Net of Tax	-	(91)	(507)	(7)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	237	(23)	(21)	-	-	-	193
Net Income (Loss)	1,455	(404)	(528)	(284)	(129)	-	110
Depreciation, Depletion and Amortization Expense	1,241	18	-	39	1	-	1,299
Total Assets	30,816	2,405	1,705	1,697	14,925	(14,804)	36,744
Assets Held for Sale	1,033	240	1,624	185	-	-	3,082
Investments in Equity							
Method Subsidiaries	-	36	38	87	-	-	161
Gross Property Additions	1,323	25	-	10	-	-	1,358

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

		<u>Investments</u>					
	<u>Utility</u>	<u>Gas</u>	<u>UK</u>	<u>Other</u>	<u>All</u>	<u>Reconciling</u>	<u>Consolidated</u>
	<u>Operations</u>	<u>Operations</u>	<u>Operations</u>	<u>Other</u>	<u>Other</u> *	<u>Adjustments</u>	
				(in millions)			
2002							
Revenues from:							
External Customers	\$10,446	\$2,071	\$-	\$791	\$-	\$ -	\$13,308
Other Operating Segments	-	222	-	147	10	(379)	-
Discontinued Operations,							
Net of Tax	-	8	(472)	(190)	-	-	(654)
Cumulative Effect of							
Accounting Changes,							
Net of Tax	-	-	-	(350)	-	-	(350)
Net Income (Loss)	1,154	(91)	(472)	(1,062)	(48)	-	(519)
Depreciation, Depletion							
and Amortization Expense	1,268	13	-	67	-	-	1,348
Total Assets	29,431	3,912	1,215	1,947	18,388	(19,003)	35,890
Assets Held for Sale	1,866	375	1,150	210	-	-	3,601
Investments in Equity							
Method Subsidiaries	-	35	-	137	-	-	172
Gross Property Additions	1,517	47	-	25	96	-	1,685

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

		<u>Investments</u>					
	<u>Utility</u>	<u>Gas</u>	<u>UK</u>	<u>Other</u>	<u>All</u>	<u>Reconciling</u>	<u>Consolidated</u>
	<u>Operations</u>	<u>Operations</u>	<u>Operations</u>	<u>Other</u>	<u>Other</u> *	<u>Adjustments</u>	
				(in millions)			
2001							
Revenues from:							
External Customers	\$10,546	\$1,797	\$-	\$410	\$-	\$-	\$12,753
Other Operating Segments	-	-	-	86	5	(91)	-
Discontinued Operations,							
Net of Tax	-	(4)	(41)	86	-	-	41
Extraordinary Items,							
Net of Tax	(48)	-	-	-	-	-	(48)
Cumulative Effect,							
Net of Tax	-	-	-	18	-	-	18
Net Income (Loss)	911	87	(41)	86	(72)	-	971
Depreciation, Depletion and							
Amortization Expense	1,193	15	-	25	-	-	1,233
Gross Property Additions	1,397	14	-	137	98	-	1,646

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. We recorded a favorable transition adjustment to Accumulated Other Comprehensive Income (Loss) of \$27 million at January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures. Most of the derivatives identified in the transition adjustment were designated as cash flow hedges and relate to foreign operations.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge, a cash flow hedge or a hedge of a net investment in a foreign operation. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statement of Operations 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 Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change. For a hedge of a net investment in a foreign currency, we include the effective portion of the gain or loss in Other Accumulated Comprehensive Income as part of the cumulative translation adjustment. We recognize any ineffective portion of the gain or loss in Revenues immediately during the period of change.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either “Risk Management Assets” or “Risk Management Liabilities.” We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Fair Value Hedging Strategies

We enter into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of the hedging activity is to protect the natural gas inventory against changes in fair value due to changes in the spot gas prices. During the year ended December 31, 2003, we recognized a pre-tax loss of approximately \$3.4 million within revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into 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 the foreign currencies, the decline in value of future foreign currency revenue 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. We do not hedge all foreign currency exposure.

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

We enter into forward and swap transactions for the purchase and sale of electricity and natural gas to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impacts

of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2003 are:

	<u>Hedging Assets</u>	<u>Hedging Liabilities</u>	<u>Accumulated Other Comprehensive Income (Loss) After Tax</u> (in millions)	<u>Portion Expected to Be Reclassified to Earnings during the Next 12 Months</u>
Power and Gas	\$21	\$(121)	\$(65)	\$(58)
Interest Rate	-	(7)	(9)*	(8)
Foreign Currency	-	(30)	<u>(20)</u>	<u>(20)</u>
			<u>\$(94)</u>	<u>\$(86)</u>

* Includes \$6 million loss recorded in an equity investment.

The net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 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 five years.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in millions)
Beginning Balance, January 1, 2003	\$(16)
Changes in fair value	(79)
Reclasses from AOCI to net gain	<u>1</u>
Ending Balance, December 31, 2003	<u>\$(94)</u>

Hedge of Net Investment in Foreign Operations

In 2001 and 2002, we used foreign denominated fixed-rate debt to protect the value of our investments in foreign subsidiaries in the U.K. Realized gains and losses from these hedges are not included in the income statement, but are shown in the cumulative translation adjustment account included in Other Accumulated Comprehensive Income.

During 2002, we recognized \$64 million of net losses, included in the cumulative translation adjustment, related to the foreign denominated fixed-rate debt.

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, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	<u>Book Value</u>	<u>Fair Value</u>	<u>Book Value</u>	<u>Fair Value</u>
	(in millions)		(in millions)	
Long-term Debt	\$14,101	\$14,621	\$10,190	\$10,535
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption*	76	76	84	77
Trust Preferred Securities	-	-	321	324

* See Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries for the effect of SFAS 150 in 2003.

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 “Accounting for Certain Investments in Debt and Equity Securities.” At December 31, 2003 and 2002, the fair values of the trust investments were \$1,107 million and \$969 million, respectively, and had a cost basis of \$995 million and \$909 million, respectively. The change in market value in 2003, 2002, and 2001 was a net unrealized holding gain of \$53 million and a net unrealized holding loss of \$33 million and \$11 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary items, and cumulative effect as reported are as follows:

	<u>Year Ended December 31,</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
Federal:			
Current	\$297	\$307	\$411
Deferred	<u>34</u>	<u>(60)</u>	<u>54</u>
Total	<u>331</u>	<u>247</u>	<u>465</u>
State and Local:			
Current	19	32	61
Deferred	<u>1</u>	<u>28</u>	<u>34</u>
Total	<u>20</u>	<u>60</u>	<u>95</u>
International:			
Current	7	8	(7)
Deferred	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>7</u>	<u>8</u>	<u>(7)</u>
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	<u><u>\$358</u></u>	<u><u>\$315</u></u>	<u><u>\$553</u></u>

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

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Net Income (Loss)	\$110	\$(519)	\$971
Discontinued Operations (net of income tax of \$312 million, \$174 million and \$14 million in 2003, 2002 and 2001, respectively)	605	654	(41)
Extraordinary Items (net of income tax of \$20 million in 2001)	-	-	48
Cumulative Effect of Accounting Change (net of income tax of \$138 million in 2003)	(193)	350	(18)
Preferred Stock Dividends	9	11	10
Income Before Preferred Stock Dividends of Subsidiaries	531	496	970
Income Taxes Before Discontinued Operations, Extraordinary Items and Cumulative Effect	358	315	553
Pre-Tax Income	<u>\$889</u>	<u>\$811</u>	<u>\$1,523</u>
Income Taxes on Pre-Tax Income at Statutory Rate (35%)	\$311	\$284	\$533
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	40	32	48
Asset Impairments and Investment Value Losses	23	4	-
Investment Tax Credits (net)	(33)	(35)	(37)
Tax Effects of International Operations	8	27	(22)
Energy Production Credits	(15)	(14)	-
State Income Taxes	13	39	62
Other	11	(22)	(31)
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	<u>\$358</u>	<u>\$315</u>	<u>\$553</u>
Effective Income Tax Rate	40.3%	38.8%	36.3%

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

	As of December 31,	
	2003	2002
	(in millions)	
Deferred Tax Assets	\$3,354	\$2,604
Deferred Tax Liabilities	(7,311)	(6,520)
Net Deferred Tax Liabilities	<u>\$(3,957)</u>	<u>\$(3,916)</u>
Property Related Temporary Differences	\$(2,836)	\$(3,195)
Amounts Due From Customers For Future Federal Income Taxes	(389)	(360)
Deferred State Income Taxes	(416)	(422)
Transition Regulatory Assets	(254)	(234)
Regulatory Assets Designated for Securitization	(281)	(310)
Deferred Income Taxes on Other Comprehensive Loss	306	326
All Other (net)	(87)	279
Net Deferred Tax Liabilities	<u>\$(3,957)</u>	<u>\$(3,916)</u>

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 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.

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 is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

16. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31,		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
Lease Payments on Operating Leases	\$330	\$346	\$292
Amortization of Capital Leases	64	65	82
Interest on Capital Leases	<u>9</u>	<u>14</u>	<u>22</u>
Total Lease Rental Costs	<u>\$403</u>	<u>\$425</u>	<u>\$396</u>

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	\$37	\$40
Distribution	15	15
Other	<u>470</u>	<u>687</u>
Total Property, Plant and Equipment	522	742
Accumulated Amortization	<u>218</u>	<u>299</u>
Net Property, Plant and Equipment Under Capital Leases	<u>\$304</u>	<u>\$443</u>
Obligations Under Capital Leases:		
Noncurrent Liability	\$131	\$170
Liability Due Within One Year	<u>51</u>	<u>58</u>
Total Obligations under Capital Leases	<u>\$182</u>	<u>\$228</u>

Future minimum lease payments consisted of the following at December 31, 2003:

	<u>Capital Leases</u>	<u>Noncancelable Operating Leases</u>
	<u>(in millions)</u>	
2004	\$63	\$291
2005	43	255
2006	34	237
2007	31	227
2008	18	214
Later Years	<u>31</u>	<u>2,331</u>
Total Future Minimum Lease Payments	220	<u>\$3,555</u>
Less Estimated Interest Element	<u>38</u>	
Estimated Present Value of Future Minimum Lease Payments	<u>\$182</u>	

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a “qualifying cogeneration facility” for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated 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 with debt financing up to \$494 million and equity up to \$31 million from investors with no relationship to AEP or any of AEP’s subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded \$496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper’s acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP’s lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper’s debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. 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 an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease 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 \$396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the \$396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled \$496 million, and total costs for the completed Facility are currently expected to be approximately \$525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately \$18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to \$396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected \$396 million of the \$496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is \$396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of \$496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to 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 non-conforming.

See further discussion in Notes 7 and 10.

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, 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 lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of \$90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG (\$469.6 million). OPCo now records the depreciation, interest and other operating

expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

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). 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 are \$1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

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 payment included in the future minimum lease payments schedule earlier in this note. 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 the term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2003, the maximum potential loss was approximately \$31.5 million (\$20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, \$321 million (\$75 million PSO, \$110 million SWEPCo and \$136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The \$10 million investment in the trust is now reported as Other within Other Non-Current Assets while the \$331 million of subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt.

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

<u>Business Trust</u>	<u>Security</u>	<u>Units Issued/ Outstanding at 12/31/03</u>	<u>Amount in Other at 12/31/03 (a)</u> (in millions)	<u>Amount in Notes Payable to Trust at 12/31/03 (b)</u> (in millions)	<u>Amount Reported Prior to FIN 46 at 12/31/02 (c)</u> (in millions)	<u>Description of Underlying Debentures of Registrant</u>
CPL Capital I	8.00%, Series A	5,450,000	\$5	\$141	\$136	TCC, \$141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, \$77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, \$113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	<u>110,000</u>	<u>3</u>	<u>113</u>	<u>-</u>	SWEPCo, \$113 million, 5.25% five year fixed rate period, Series B
Total		<u>8,560,000</u>	<u>\$10</u>	<u>\$331</u>	<u>\$321</u>	

(a) Amounts are in Other within Other Non-Current Assets.

(b) Amounts are in Notes Payable to Trust within Long-term Debt.

(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies 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 was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and \$321.4 million of AEP Energy Services Gas Holding Company (AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into AEP common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with \$2 million cash and a subscription agreement that represents an unconditional obligation to fund \$83 million from SubOne for a managing member interest and \$750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead is an unconsolidated special purpose entity and had an original capital structure of \$750 million (currently approximately \$525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The \$525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the proposed sale of LIG will be used to reduce the outstanding balance of the loan from Caddis (see Note 10 for additional information on LIG and HPL).

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary (\$759 million at December 31, 2002 and \$533 million at June 30, 2003). As a result, a note payable to Caddis is reported as a component of Long-term Debt (\$527 million at December 31, 2003). 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.

On May 9, 2003, SubOne borrowed \$225 million from us and used the proceeds to reduce the outstanding balance of the loan from Caddis, which Caddis used to reduce the preferred interest held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP common stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of outstanding debt in excess of \$50 million would be an event of default under the credit agreement.

SubOne has deposited \$422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

Caddis and SubOne are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from us.

Equity Units

In June 2002, AEP issued 6.9 million equity units at \$50 per unit and received proceeds of \$345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is \$50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If the holders elect to allow the notes to be remarketed, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of \$50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders' requirement to purchase common stock under the forward purchase contracts.

AEP is making quarterly interest payments on the senior notes at an initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP makes contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments was recorded as a \$31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital in June 2002. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

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 non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling \$2.9 billion to support our commercial paper program. At December 31, 2003, AEP had \$326 million outstanding in short-term borrowings of which \$282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of \$26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 16 “Leases”. This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was \$1.5 billion during January 2003. On December 11, 2002, Moody’s Investor Services placed AEP’s Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor’s Rating Services placed AEP’s A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody’s Investor Services downgraded AEP’s short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor’s Rating Services reaffirmed AEP’s A-2 short-term rating for commercial paper.

Outstanding Short-term Debt consisted of:

	<u>December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Balance Outstanding:		
Notes Payable	\$18	\$1,322
Commercial Paper - AEP	282	1,417
Commercial Paper - JMG	<u>26</u>	<u>-</u>
Total	<u>\$326</u>	<u>\$2,739</u>

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, 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 does not consolidate these entities in accordance with GAAP. We continue 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 the AEP operating companies’ receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of \$600 million to purchase receivables from AEP Credit. At December 31, 2003, \$385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the 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 and, until the first quarter of 2002, with non-affiliated companies. 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. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant

Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company), were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Proceeds from Sale of Accounts Receivable	\$5,221	\$5,513
Accounts Receivable Retained Interest Less Uncollectible		
Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	<u>Face Value</u>	
	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Customer Accounts Receivable Retained	\$1,155	\$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	<u>(124)</u>	<u>(108)</u>
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	<u>385</u>	<u>454</u>
Total Accounts Receivable Managed	<u>\$2,095</u>	<u>\$2,543</u>
Net Uncollectible Accounts Written Off	<u>\$39</u>	<u>\$48</u>

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.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was \$30 million.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

<u>(In Millions – Except Per Share Amounts)</u>	<u>2003 Quarterly Periods Ended</u>			
	<u>March 31</u>	<u>June 30</u>	<u>September 30</u>	<u>December 31</u>
Revenues	\$3,834	\$3,451	\$3,940	\$3,320
Operating Income (Loss)	630	393	735	(126)
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	294	185	298	(255)
Net Income (Loss)	440	175	257	(762)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect*	0.83	0.47	0.75	(0.65)
Earnings (Loss) per Share**	1.24	0.44	0.65	(1.93)

<u>(In Millions – Except Per Share Amounts)</u>	<u>2002 Quarterly Periods Ended</u>			
	<u>March 31</u>	<u>June 30</u>	<u>September 30</u>	<u>December 31</u>
Revenues	\$2,802	\$3,395	\$3,639	\$3,472
Operating Income	420	433	781	170
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	134	167	385	(201)
Net Income (Loss)	(169)	62	425	(837)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect***	0.42	0.51	1.14	(0.59)
Earnings (Loss) per Share****	(0.53)	0.19	1.25	(2.47)

* Amounts for 2003 do not add to \$1.35 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding and the dilutive effect of shares issued in 2003.

** Amounts for 2003 do not add to \$0.29 earnings per share due to rounding and the dilutive effect of shares issued in 2003.

*** Amounts for 2002 do not add to \$1.46 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding.

**** Amounts for 2002 do not add to \$(1.57) earnings per share due to rounding.

Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect for the fourth quarter 2003 (\$255 million loss) and 2002 (\$201 million loss) were significantly lower than the previous three quarters due to asset impairments, investment value losses and other related charges. These pre-tax writedowns (\$650 million in the fourth quarter 2003 and \$593 million in the fourth quarter 2002) were made to reflect impairments and discontinued operations as discussed in Note 10.

19. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003, we entered into separate agreements to dispose of the following investments:

<u>Investment</u>	<u>Sales Price</u> <u>(in millions)</u>	<u>Date of Agreement</u>
Oklaunion Power Station	\$42.8	January 30, 2004
LIG Pipeline and its subsidiaries	\$76.2	February 13, 2004
STP	\$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

The Nanyang General Light (Pushan) investment was sold for \$60.7 million on March 2, 2004. This sale had no significant impact on our results of operations.

On March 10, 2004, we entered into an agreement to sell four domestic Independent Power Producer (IPP) investments for a sales price of \$156 million. We anticipate this sale to be completed during 2004 and to result in a pre-tax gain of approximately \$100 million.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and common shareholders' equity and comprehensive income, for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 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 142, "Goodwill and Other Intangible Assets," effective January 1, 2002.

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 2 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
March 5, 2004

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. (the Company) has prepared the financial statements and schedules herein and is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with accounting principles generally accepted in the United States of America, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee. The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the previous page.

AEP GENERATING COMPANY

**AEP GENERATING COMPANY
SELECTED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>
	(in thousands)				
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$233,165	\$213,281	\$227,548	\$228,516	\$217,189
Operating Expenses	<u>225,991</u>	<u>207,152</u>	<u>220,571</u>	<u>220,092</u>	<u>211,849</u>
Operating Income	7,174	6,129	6,977	8,424	5,340
Nonoperating Items, Net	3,340	3,681	3,484	3,429	3,659
Interest Charges	<u>2,550</u>	<u>2,258</u>	<u>2,586</u>	<u>3,869</u>	<u>2,804</u>
Net Income	<u>\$7,964</u>	<u>\$7,552</u>	<u>\$7,875</u>	<u>\$7,984</u>	<u>6,195</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$674,055	\$652,213	\$648,254	\$642,302	\$640,093
Accumulated Depreciation	<u>351,062</u>	<u>330,187</u>	<u>310,804</u>	<u>290,858</u>	<u>271,941</u>
Net Electric Utility Plant	<u>\$322,993</u>	<u>\$322,026</u>	<u>\$337,450</u>	<u>\$351,444</u>	<u>\$368,152</u>
TOTAL ASSETS	<u>\$380,045</u>	<u>\$377,716</u>	<u>\$387,688</u>	<u>\$399,310</u>	<u>\$421,764</u>
Common Stock and Paid-in Capital	\$24,434	\$24,434	\$24,434	\$24,434	\$30,235
Retained Earnings	<u>21,441</u>	<u>18,163</u>	<u>13,761</u>	<u>9,722</u>	<u>3,673</u>
Total Common Shareholder's Equity	<u>\$45,875</u>	<u>\$42,597</u>	<u>\$38,195</u>	<u>\$34,156</u>	<u>\$33,908</u>
Long-term Debt (a)	<u>\$44,811</u>	<u>\$44,802</u>	<u>\$44,793</u>	<u>\$44,808</u>	<u>\$44,800</u>
Obligations Under Capital Leases (a)	<u>\$269</u>	<u>\$501</u>	<u>\$311</u>	<u>\$591</u>	<u>\$867</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$380,045</u>	<u>\$377,716</u>	<u>\$387,688</u>	<u>\$399,310</u>	<u>\$421,764</u>

(a) Including portion due within one year.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEGCo, co-owner of the Rockport Plant, is engaged 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 AEGCo's 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. This assignment expires December 31, 2004.

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, AEGCo accumulates all expenses monthly and prepares bills for its affiliates. In the month the expenses are incurred, AEGCo recognizes the billing revenues and establishes a receivable from the affiliated companies.

Results of Operations

2003 Compared to 2002

Net Income increased \$412 thousand for the year 2003 compared with the year 2002. The fluctuations in Net Income are a result of terms in the unit power agreements which allow for the return on total capital of the Rockport Plant calculated and adjusted monthly.

Operating Income

Operating Income increased \$1 million for the year 2003 compared with the year 2002 primarily due to:

- A \$20 million increase in Operating Revenue as a result of increased recoverable expenses, primarily Fuel for Electric Generation, in accordance with the unit power agreements along with increased return on total capital.
- A \$2 million decrease in Maintenance and Other Operation expense. This decrease is due primarily to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits allocated to AEGCo in 2002.

The increase in Operating Income was partially offset by:

- A \$20 million increase in Fuel for Electric Generation expense. This increase is primarily due to an increase in the average cost of coal and an 8% increase in MWH generation.

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:

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 \$1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

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. 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 the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
<u>Contractual Cash Obligations</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Long-term Debt	\$-	\$-	\$-	\$45	\$45
Advances from Affiliates	37	-	-	-	37
Unconditional Purchase Obligations (a)	82	75	75	161	393
Noncancellable Operating Leases	<u>74</u>	<u>148</u>	<u>148</u>	<u>1,033</u>	<u>1,403</u>
Total	<u>\$193</u>	<u>\$223</u>	<u>\$223</u>	<u>\$1,239</u>	<u>\$1,878</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under “Off-Balance Sheet Arrangements” above, have been employed for a contractual cash obligation reported in the above table. The lease of Rockport Unit 2 is reported in Noncancellable Operating Leases.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES	<u>\$233,165</u>	<u>\$213,281</u>	<u>\$227,548</u>
OPERATING EXPENSES			
Fuel for Electric Generation	109,238	89,105	102,828
Rent – Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	10,399	12,924	11,025
Maintenance	10,346	9,418	8,853
Depreciation	22,686	22,560	22,423
Taxes Other Than Income Taxes	3,396	3,281	4,257
Income Taxes	<u>1,643</u>	<u>1,581</u>	<u>2,902</u>
TOTAL	<u>225,991</u>	<u>207,152</u>	<u>220,571</u>
OPERATING INCOME	7,174	6,129	6,977
Nonoperating Income	151	344	30
Nonoperating Expenses	361	199	16
Nonoperating Income Tax Credits	3,550	3,536	3,470
Interest Charges	<u>2,550</u>	<u>2,258</u>	<u>2,586</u>
NET INCOME	<u><u>\$7,964</u></u>	<u><u>\$7,552</u></u>	<u><u>\$7,875</u></u>

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
BALANCE AT BEGINNING OF PERIOD	\$18,163	\$13,761	\$9,722
Net Income	7,964	7,552	7,875
Cash Dividends Declared	<u>4,686</u>	<u>3,150</u>	<u>3,836</u>
BALANCE AT END OF PERIOD	<u><u>\$21,441</u></u>	<u><u>\$18,163</u></u>	<u><u>\$13,761</u></u>

The common stock of AEGCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$645,251	\$637,095
General	4,063	4,728
Construction Work in Progress	<u>24,741</u>	<u>10,390</u>
TOTAL	674,055	652,213
Accumulated Depreciation	<u>351,062</u>	<u>330,187</u>
TOTAL - NET	<u>322,993</u>	<u>322,026</u>
 OTHER PROPERTY AND INVESTMENTS – Non-Utility		
Property, Net	<u>119</u>	<u>119</u>
 <u>CURRENT ASSETS</u>		
Accounts Receivable – Affiliated Companies	24,748	18,454
Fuel	20,139	20,260
Materials and Supplies	<u>5,419</u>	<u>4,913</u>
TOTAL	<u>50,306</u>	<u>43,627</u>
 <u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,733	4,970
Asset Retirement Obligations	928	-
Deferred Charges	<u>966</u>	<u>6,974</u>
TOTAL	<u>6,627</u>	<u>11,944</u>
 TOTAL ASSETS	<u>\$380,045</u>	<u>\$377,716</u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
<hr/> CAPITALIZATION <hr/>		
Common Shareholder's Equity:		
Common Stock – Par Value \$1,000 per share:		
Authorized and Outstanding – 1,000 Shares	\$1,000	\$1,000
Paid-in Capital	23,434	23,434
Retained Earnings	<u>21,441</u>	<u>18,163</u>
Total Common Shareholder's Equity	45,875	42,597
Long-term Debt	<u>44,811</u>	<u>44,802</u>
TOTAL	<u>90,686</u>	<u>87,399</u>
<hr/> CURRENT LIABILITIES <hr/>		
Advances from Affiliates	36,892	28,034
Accounts Payable:		
General	498	26
Affiliated Companies	15,911	15,907
Taxes Accrued	6,070	2,327
Interest Accrued	911	911
Obligations Under Capital Leases	87	200
Rent Accrued – Rockport Plant Unit 2	<u>4,963</u>	<u>4,963</u>
TOTAL	<u>65,332</u>	<u>52,368</u>
<hr/> DEFERRED CREDITS AND OTHER LIABILITIES <hr/>		
Deferred Income Taxes	24,329	29,002
Regulatory Liabilities:		
Asset Removal Costs	27,822	-
Deferred Investment Tax Credits	49,589	52,943
SFAS 109 Regulatory Liability, Net	15,505	16,670
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	105,475	111,046
Obligations Under Capital Leases	182	301
Asset Retirement Obligations	1,125	-
Other	<u>-</u>	<u>27,987</u>
TOTAL	<u>224,027</u>	<u>237,949</u>
<hr/>		
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	\$380,045	\$377,716

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$7,964	\$7,552	\$7,875
Adjustments to Reconcile Net Income to Net Cash			
Flows From Operating Activities:			
Depreciation	22,686	22,560	22,423
Deferred Income Taxes	(5,838)	(5,028)	(6,224)
Deferred Investment Tax Credits	(3,354)	(3,361)	(3,414)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Certain Assets and Liabilities:			
Accounts Receivable	(6,294)	4,037	1,224
Fuel, Materials and Supplies	(385)	(5,450)	(4,738)
Accounts Payable	476	6,697	(4,597)
Taxes Accrued	3,743	(2,450)	(216)
Deferred Property Taxes	(45)	190	(49)
Change in Other Assets	3,531	(5,401)	(520)
Change in Other Liabilities	1,007	(2,295)	(1,244)
Net Cash Flows From Operating Activities	<u>17,920</u>	<u>11,480</u>	<u>4,949</u>
INVESTING ACTIVITIES			
Construction Expenditures	(22,197)	(5,298)	(6,868)
Proceeds From Sale of Assets	105	-	-
Net Cash Flows Used For Investing Activities	<u>(22,092)</u>	<u>(5,298)</u>	<u>(6,868)</u>
FINANCING ACTIVITIES			
Change in Advances from Affiliates	8,858	(4,015)	3,981
Dividends Paid	(4,686)	(3,150)	(3,836)
Net Cash Flows From (Used For) Financing Activities	<u>4,172</u>	<u>(7,165)</u>	<u>145</u>
Net Decrease in Cash and Cash Equivalents	-	(983)	(1,774)
Cash and Cash Equivalents at Beginning of Period	-	983	2,757
Cash and Cash Equivalents at End of Period	<u>\$-</u>	<u>\$-</u>	<u>\$983</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$2,283,000, \$2,019,000 and \$1,509,000 and for income taxes was \$6,483,000, \$7,884,000 and \$8,597,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
COMMON SHAREHOLDER'S EQUITY	<u>\$45,875</u>	<u>\$42,597</u>
LONG-TERM DEBT:		
Installment Purchase Contracts – City of Rockport (a)		
<u>Series</u> <u>Due Date</u>		
1995 A 2025 (b)	22,500	22,500
1995 B 2025 (b)	22,500	22,500
Unamortized Discount	<u>(189)</u>	<u>(198)</u>
TOTAL LONG-TERM DEBT	<u>44,811</u>	<u>44,802</u>
TOTAL CAPITALIZATION	<u>\$90,686</u>	<u>\$87,399</u>

- (a) Installment purchase contracts were entered into in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. The terms of the installment purchase contracts require AEGCo to pay amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant.
- (b) These series have an adjustable interest rate that can be a daily, weekly, commercial paper or term rate as designated by AEGCo. Prior to July 13, 2001, AEGCo had selected a daily rate which ranged from 0.9% to 5.6% during 2001 and averaged 2.8% in 2001. Effective July 13, 2001, AEGCo selected a term rate of 4.05% for five years ending July 12, 2006.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to AEGCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to AEGCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Effects of Regulation	Note 5
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of AEP Generating Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Generating Company as of December 31, 2003 and 2002, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

**AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SELECTED CONSOLIDATED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>
	(in thousands)				
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,747,511	\$1,690,493	\$1,738,837	\$1,770,402	\$1,482,475
Operating Expenses	<u>1,425,971</u>	<u>1,296,760</u>	<u>1,443,106</u>	<u>1,463,304</u>	<u>1,188,490</u>
Operating Income	321,540	393,733	295,731	307,098	293,985
Nonoperating Items, Net	29,819	8,079	2,815	7,235	2,596
Interest Charges	<u>133,812</u>	<u>125,871</u>	<u>116,268</u>	<u>124,766</u>	<u>114,380</u>
Income Before Cumulative Effect of Accounting Change	217,547	275,941	182,278	189,567	182,201
Cumulative Effect of Accounting Change (Net of Tax)	<u>122</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	217,669	275,941	182,278	189,567	182,201
Preferred Stock Dividend Requirements	241	241	242	241	6,931
Gain (Loss) on Reacquired Preferred Stock	<u>-</u>	<u>4</u>	<u>-</u>	<u>-</u>	<u>(2,763)</u>
Earnings Applicable To Common Stock	<u>\$217,428</u>	<u>\$275,704</u>	<u>\$ 182,036</u>	<u>\$189,326</u>	<u>\$ 172,507</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$2,425,038	\$2,334,794	\$2,231,287	\$2,097,497	\$1,996,374
Accumulated Depreciation and Amortization	<u>695,359</u>	<u>662,345</u>	<u>616,526</u>	<u>570,522</u>	<u>598,275</u>
Net Electric Utility Plant	<u>\$1,729,679</u>	<u>\$1,672,449</u>	<u>\$1,614,761</u>	<u>\$1,526,975</u>	<u>\$1,398,099</u>
TOTAL ASSETS	<u>\$5,824,707</u>	<u>\$5,453,960</u>	<u>\$4,989,381</u>	<u>\$5,556,275</u>	<u>\$4,930,547</u>
Common Stock and Paid-in Capital	\$187,898	\$187,898	\$573,903	\$573,904	\$573,904
Retained Earnings	1,083,023	986,396	826,197	792,219	758,894
Accumulated Other Comprehensive Income (Loss)	<u>(61,872)</u>	<u>(73,160)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u>\$1,209,049</u>	<u>\$1,101,134</u>	<u>\$1,400,100</u>	<u>\$1,366,123</u>	<u>\$1,332,798</u>
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>\$5,940</u>	<u>\$5,942</u>	<u>\$5,952</u>	<u>\$5,951</u>	<u>\$5,951</u>
Trust Preferred Securities (a)	<u>\$-</u>	<u>\$136,250</u>	<u>\$136,250</u>	<u>\$148,500</u>	<u>\$150,000</u>
Long-term Debt (b)	<u>\$2,291,625</u>	<u>\$1,438,565</u>	<u>\$1,253,768</u>	<u>\$1,454,559</u>	<u>\$1,454,541</u>
Obligations Under Capital Leases (b)	<u>\$1,043</u>	<u>\$-</u>	<u>\$-</u>	<u>\$-</u>	<u>\$-</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$5,824,707</u>	<u>\$5,453,960</u>	<u>\$4,989,381</u>	<u>\$5,556,275</u>	<u>\$4,930,547</u>

(a) See Note 16 of the Notes to Respective Financial Statements.

(b) Including portion due within one year.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

AEP Texas Central Company (TCC), formerly known as Central Power and Light Company (CPL), is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power. 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. TCC also sells electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members 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 revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

Net Income decreased \$58 million for 2003. The decrease is mainly due to an increased provision for refunds of \$85 million (\$55 million after tax) and a decrease in the recognition of non-cash earnings related to legislatively mandated capacity auctions and regulatory assets established in Texas of \$29 million net of tax. Additionally, income from transactions with ERCOT increased significantly due mainly to Texas Restructuring Legislation.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs, effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy CPL to an unrelated third party, who assumed the obligations of the affiliated REP including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy CPL were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy CPL are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income decreased \$72 million primarily due to:

- Increased provisions for rate refunds of \$85 million due mainly to 2003 Texas fuel issues (see “TCC Fuel Reconciliation” in Note 4).
- Decreased revenues associated with establishing regulatory assets in Texas of \$44 million or 17% in 2003 (see “Texas Restructuring” in Note 6). These revenues will not continue after 2003.
- Decreased system sales, including those to REPs, of \$7 million due mainly to a decrease in the overall average price per KWH and higher KWH sales of 2%.
- Decreased revenues from ERCOT for various services, including balancing energy, of \$7 million or 7%.
- The 2002 ICR adjustments which accounted for approximately \$59 million of the decrease in revenue with an offsetting \$51 million decrease in purchased power.
- Decreased retail revenues of \$24 million driven by a 9% decrease in cooling degree-days offset by a slight increase in heating degree-days. Average price per KWH decreased 2%.
- Increases in fuel and purchased electricity on a net basis of \$197 million to replace portions of the energy from the non-RMR mothballed plants and the unscheduled forced outage at the STP nuclear unit (See “Significant Factors” below). KWH purchased increased 47% while the cost increased 54%. Although the KWH generated decreased, fuel costs increased 16% due to higher per unit costs attributable mostly to natural gas.
- Increased Maintenance expense of \$8 million due mainly to the STP Unit 2 forced outage in the first quarter of 2003 and the STP Unit 1 scheduled refueling outage and forced outage in the second and third quarters of 2003.

The decrease in Operating Income was partially offset by:

- Increased Reliability Must Run (RMR) revenues from ERCOT of \$214 million which include both fuel recovery and a fixed cost component of \$35 million (see “Texas Plants” in Note 10 for discussion of RMR facilities).
- Increased margins of \$31 million resulting from risk management activities.
- Increased other operating revenue of \$25 million comprised primarily of miscellaneous service revenue and fees as a result of the Texas Restructuring Legislation.
- Decreased Other Operation expense of \$6 million due primarily to lower distribution and customer related expenses in 2003, offset in part by \$16 million of accretion expense associated with the implementation of SFAS 143, as well as increased cost of \$6 million related to 2003 ERCOT transmission charges.
- Decreased Depreciation and Amortization expense of \$25 million due mainly to decreases resulting from ARO of \$16 million (see Note 2) and reduced depreciable plant by \$6 million due to the mothballing of certain generating units in 2002.
- Decreased Taxes Other Than Income Taxes of \$3 million due mainly to reduce gross receipt taxes as a result of the sale of the Texas REPs, partially offset by higher property taxes.
- Decreased Income Taxes of \$41 million due to decreased pre-tax operating income.

Other Impacts on Earnings

Nonoperating Income increased \$1 million. While 2003 gains from risk management activities increased \$33 million, they are almost totally offset by lower 2003 revenues of \$33 million from third party non-utility energy related construction projects.

Nonoperating Expense decreased \$25 million primarily due to lower non-utility expenses associated with energy related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased \$4 million due to increased pre-tax nonoperating income partially offset by changes related to consolidated tax savings.

Interest Charges increased \$8 million primarily due to the replacement of lower cost short-term floating rate debt with longer-term higher cost fixed rate debt.

2002 Compared to 2001

In 2002, Net Income increased \$94 million primarily due to \$262 million of revenue associated with recognition of stranded costs in Texas offset in part by losses associated with the commencement of customer choice in Texas, which resulted in the loss of customers and reduced prices (see Note 6).

Operating Income

Operating Income increased \$98 million primarily due to:

- Increased revenue associated with establishing regulatory assets in Texas of \$262 million in 2002 (see “Texas Restructuring” in Note 6).
- Increased system sales, including those to REPs, of \$84 million due mainly to the newly created affiliated REP, offset by retail fuel revenue, as a result of Texas Restructuring Legislation.
- Increase revenues of \$73 million from ERCOT for various services, including balancing energy, as a result of Texas Restructuring Legislation.
- The 2002 ICR adjustments which accounted for approximately \$59 million of the increase in revenue with an offsetting \$51 million increase in purchased power (See “ICR Explanation” in Note 4 for discussion of the ICR adjustments).
- Decreased provisions for rate refunds of \$3 million due mainly to a 2001 FERC transmission tariff refund.
- Increased RMR revenues from ERCOT of \$28 million which include both fuel recovery and a fixed cost component (see “Texas Plants” in Note 10 for discussion of RMR facilities).
- Net decreases in fuel and purchased electricity on a combined basis of \$198 million due to a decrease in both generation and the average cost of fuel, offset in part by increased KWH purchased. More KWH were purchased in part due to our ability to purchase power below our cost to produce. KWH purchased increased 5% while the total cost increased 26%. The KWH generated decreased by 27% and fuel costs decreased 50%.
- Decreased Other Operation expense of \$17 million due to the elimination of factoring of accounts receivable, as well as lower ERCOT transmission charges.
- Decreased Maintenance expense of \$8 million due mainly to two scheduled “18 months interval” refueling outages for STP during 2001 that increased maintenance expense above the 2002 level. Also contributing to the decrease in 2002 was an increase in maintenance expense for scheduled major overhauls of four power plants in 2001.

The increase in Operating Income was partially offset by:

- Decreased retail revenues due to the Texas Restructuring Legislation of \$467 million in 2002 (see “Texas Restructuring” in Note 6).
- Decreased revenues of \$54 million resulting from risk management activities.
- Increased Depreciation and Amortization expense of \$46 million due mainly to the amortization of regulatory assets that were securitized in the first quarter of 2002 and being collected in revenue, offset by the elimination of excess earnings expense in 2002 under Texas Restructuring Legislation (See Note 6).
- Increased Taxes Other Than Income Taxes of \$5 million due to higher local franchise taxes, offset by one-time 2001 assessments and decreased gross receipts tax due to deregulation.

Other Impacts on Earnings

Nonoperating Income increased \$31 million primarily due to increased non-utility revenues associated with energy related construction projects for third parties offset in part by decreased interest income.

Nonoperating Expense increased \$20 million primarily due to increased non-utility expenses associated with energy related construction projects for third parties offset in part by the extraordinary loss on reacquired debt in 2001, that was reclassified to Nonoperating Expense with the implementation of SFAS 145 (See Note 1).

Nonoperating Income Tax Expense (Credit) increased \$5 million due to higher pre-tax nonoperating book income.

Interest Charges increased \$10 million primarily due to higher levels of outstanding debt.

Cumulative Effect of Accounting Change

This amount represents the one-time after-tax effect of the application of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of TCC's rating for unsecured debt from Baa1 to Baa2 and secured debt from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. With the completion of the reviews, Moody's has placed AEP and its rated subsidiaries on stable outlook. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the year ended December 31, 2003, 2002 and 2001 were as follows:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
Cash and cash equivalents at beginning of period	<u>\$85,420</u>	<u>\$10,909</u>	<u>\$14,253</u>
Cash flow from (used for):			
Operating activities	367,223	147,493	469,920
Investing activities	(134,316)	(151,502)	(194,086)
Financing activities	<u>(252,445)</u>	<u>78,520</u>	<u>(279,178)</u>
Net increase (decrease) in cash and cash equivalents	<u>(19,538)</u>	<u>74,511</u>	<u>(3,344)</u>
Cash and cash equivalents at end of period	<u><u>\$65,882</u></u>	<u><u>\$85,420</u></u>	<u><u>\$10,909</u></u>

Operating Activities

Cash flow from operating activities were \$367 million primarily due to net income as explained above, changes to Accounts Receivable, Accounts Payable and Accrued Taxes, as well as, non-cash Depreciation and Amortization partially offset by the non-cash Texas Wholesale Clawback regulatory asset recorded in 2003.

Investing Activities

Investing expenditures in 2003 were \$134 million due mostly to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Financing Activities

We obtained the additional funds needed for financing activities through new borrowings of \$962 million in 2003. Current year debt proceeds replaced both short and long-term debt.

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, 2003:

	Payments Due by Period (in thousands)				
<u>Contractual Cash Obligations</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Long-term Debt	\$237,651	\$524,838	\$121,417	\$1,407,719	\$2,291,625
Unconditional Purchase Obligations (a)	53,749	82,203	60,648	133,608	330,208
Capital Lease Obligations	450	571	110	-	1,131
Noncancellable Operating Leases	<u>6,112</u>	<u>11,104</u>	<u>8,347</u>	<u>11,272</u>	<u>36,835</u>
Total	<u>\$297,962</u>	<u>\$618,716</u>	<u>\$190,522</u>	<u>\$1,552,599</u>	<u>\$2,659,799</u>

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

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 and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in thousands)					
<u>Other Commercial Commitments</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>	
Standby Letters of Credit	\$-	\$43,000	\$-	\$-	\$43,000	
Transmission Facilities for Third Parties (a)	22,811	74,716	30,720	-	128,247	
Total	\$22,811	\$117,716	\$30,720	\$-	\$171,247	

(a) 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.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$5,414
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(2,033)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(130)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	187
Changes in Fair Value of Risk Management Contracts (e)	8,504
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	11,942
Net Cash Flow Hedge Contracts (g)	(2,812)
Ending Balance December 31, 2003	<u>\$9,130</u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b)The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d)See Note 2 “New Accounting Pronouncements Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003**

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actively Quoted – Exchange Traded Contracts	\$238	\$(99)	\$9	\$61	\$-	\$-	\$209
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1,752	1,570	576	363	208	-	4,469
Prices Based on Models and Other Valuation Methods (b)	<u>4,346</u>	<u>511</u>	<u>114</u>	<u>237</u>	<u>497</u>	<u>1,559</u>	<u>7,264</u>
Total	<u>\$6,336</u>	<u>\$1,982</u>	<u>\$699</u>	<u>\$661</u>	<u>\$705</u>	<u>\$1,559</u>	<u>\$11,942</u>

(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 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.

(c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

**Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003**

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$(36)
Changes in Fair Value (a)	(1,931)
Reclassifications from AOCI to Net Income (b)	<u>139</u>
Ending Balance December 31, 2003	<u>\$(1,828)</u>

(a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.

(b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$1,413 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

<u>December 31, 2003</u>				<u>December 31, 2002</u>			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$189	\$733	\$307	\$73	\$115	\$353	\$126	\$26

VaR Associated with Debt Outstanding

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 \$206 million and \$65 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,593,943	\$682,049	\$1,697,075
Sales to AEP Affiliates	<u>153,568</u>	<u>1,008,444</u>	<u>41,762</u>
TOTAL	<u>1,747,511</u>	<u>1,690,493</u>	<u>1,738,837</u>
OPERATING EXPENSES			
Fuel for Electric Generation	89,389	88,488	492,057
Fuel from Affiliates for Electric Generation	195,527	157,346	-
Purchased Electricity for Resale	373,388	211,358	127,816
Purchased Electricity from AEP Affiliates	19,097	23,406	58,641
Other Operation	297,878	304,094	321,227
Maintenance	71,361	63,392	71,212
Depreciation and Amortization	189,130	214,162	168,341
Taxes Other Than Income Taxes	92,109	95,500	90,916
Income Taxes	<u>98,092</u>	<u>139,014</u>	<u>112,896</u>
TOTAL	<u>1,425,971</u>	<u>1,296,760</u>	<u>1,443,106</u>
OPERATING INCOME	321,540	393,733	295,731
Nonoperating Income	54,172	53,141	22,552
Nonoperating Expenses	17,273	41,910	21,486
Nonoperating Income Tax Expense (Credit)	7,080	3,152	(1,749)
Interest Charges	<u>133,812</u>	<u>125,871</u>	<u>116,268</u>
Income Before Cumulative Effect of Accounting Change	217,547	275,941	182,278
Cumulative Effect of Accounting Change (Net of Tax)	<u>122</u>	<u>-</u>	<u>-</u>
NET INCOME	217,669	275,941	182,278
Gain on Reacquired Preferred Stock	-	4	-
Preferred Stock Dividend Requirements	<u>241</u>	<u>241</u>	<u>242</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$217,428</u>	<u>\$275,704</u>	<u>\$182,036</u>

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$168,888	\$405,015	\$792,219	\$-	\$1,366,122
Common Stock Dividends Declared			(148,057)		(148,057)
Preferred Stock Dividends Declared			(242)		(242)
Other			(1)		(1)
TOTAL					<u>1,217,822</u>
COMPREHENSIVE INCOME					
NET INCOME			182,278		<u>182,278</u>
TOTAL COMPREHENSIVE INCOME					<u>182,278</u>
DECEMBER 31, 2001	\$168,888	\$405,015	\$826,197	\$-	\$1,400,100
Redemption of Common Stock	(113,596)	(272,409)			(386,005)
Common Stock Dividends			(115,505)		(115,505)
Preferred Stock Dividends			(241)		(241)
Gain on Reacquired Preferred Stock			4		4
TOTAL					<u>898,353</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(36)	(36)
Minimum Pension Liability				(73,124)	(73,124)
NET INCOME			275,941		<u>275,941</u>
TOTAL COMPREHENSIVE INCOME					<u>202,781</u>
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					<u>980,092</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,792)	(1,792)
Minimum Pension Liability				13,080	13,080
NET INCOME			217,669		<u>217,669</u>
TOTAL COMPREHENSIVE INCOME					<u>228,957</u>
DECEMBER 31, 2003	<u>\$55,292</u>	<u>\$132,606</u>	<u>\$1,083,023</u>	<u>\$(61,872)</u>	<u>\$1,209,049</u>

See Notes to Respective Financial Statements beginning on page L-1.

**AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS**

ASSETS

December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	\$-	\$-
Transmission	767,970	682,780
Distribution	1,376,761	1,296,731
General	221,354	202,418
Construction Work in Progress	58,953	152,865
TOTAL	2,425,038	2,334,794
Accumulated Depreciation and Amortization	695,359	662,345
TOTAL - NET	1,729,679	1,672,449
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,302	2,385
Other Investments	4,639	354
TOTAL	5,941	2,739
CURRENT ASSETS		
Cash and Cash Equivalents	65,882	85,420
Advances to Affiliates	60,699	-
Accounts Receivable:		
Customers	146,630	113,014
Affiliated Companies	78,484	121,324
Accrued Unbilled Revenues	23,077	27,150
Miscellaneous	-	529
Allowance for Uncollectible Accounts	(1,710)	(346)
Materials and Supplies	11,708	14,376
Risk Management Assets	22,051	22,493
Margin Deposits	3,230	121
Prepayments and Other Current Assets	6,770	2,012
TOTAL	416,821	386,093
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,249	9,950
Wholesale Capacity Auction True-up	480,000	262,000
Unamortized Loss on Reacquired Debt	9,086	8,661
Designated for Securitization	1,253,289	330,960
Deferred Debt – Restructuring	12,015	13,324
Other	133,913	170,101
Securitized Transition Assets	689,399	734,591
Long-term Risk Management Assets	7,627	4,392
Deferred Charges	55,554	43,890
TOTAL	2,644,132	1,577,869
Assets Held for Sale – Texas Generation Plants	1,028,134	1,814,810
TOTAL ASSETS	\$5,824,707	\$5,453,960

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – \$25 Par Value:		
Authorized – 12,000,000 Shares		
Outstanding – 2,211,678 Shares	\$55,292	\$55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,083,023	986,396
Accumulated Other Comprehensive Income (Loss)	<u>(61,872)</u>	<u>(73,160)</u>
Total Common Shareholder's Equity	1,209,049	1,101,134
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>5,940</u>	<u>5,942</u>
Total Shareholder's Equity	1,214,989	1,107,076
CPL – Obligated Mandatorily Redeemable Preferred Securities of		
Subsidiary Trust Holding Solely Junior Subordinated Debentures of TCC	-	136,250
Long-term Debt	<u>2,053,974</u>	<u>1,209,434</u>
TOTAL	<u>3,268,963</u>	<u>2,452,760</u>
CURRENT LIABILITIES		
Short-term Debt – Affiliates	-	650,000
Long-term Debt Due Within One Year	237,651	229,131
Advances from Affiliates	-	126,711
Accounts Payable:		
General	90,004	72,199
Affiliated Companies	74,209	36,242
Customer Deposits	1,517	666
Taxes Accrued	67,018	24,791
Interest Accrued	43,196	51,205
Risk Management Liabilities	17,888	19,811
Obligation Under Capital Leases	407	-
Other	<u>23,248</u>	<u>36,698</u>
TOTAL	<u>555,138</u>	<u>1,247,454</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,244,912	1,261,252
Long-term Risk Management Liabilities	2,660	1,713
Regulatory Liabilities:		
Asset Removal Costs	95,415	-
Deferred Investment Tax Credits	112,479	117,686
Deferred Fuel Costs	69,026	69,026
Retail Clawback	45,527	51,926
Other	56,984	76,547
Obligation Under Capital Leases	636	-
Deferred Credits and Other	<u>144,833</u>	<u>166,711</u>
TOTAL	<u>1,772,472</u>	<u>1,744,861</u>
Liabilities Held for Sale – Texas Generation Plants	<u>228,134</u>	<u>8,885</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u><u>\$5,824,707</u></u>	<u><u>\$5,453,960</u></u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$217,669	\$275,941	\$182,278
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Depreciation and Amortization	189,130	214,162	168,341
Deferred Income Taxes	19,393	113,655	(72,568)
Deferred Investment Tax Credits	(5,207)	(5,206)	(5,208)
Cumulative Effect of Accounting Change	(122)	-	-
Mark-to-Market of Risk Management Contracts	(6,341)	(1,558)	(12,048)
Wholesale Capacity Auction True-up	(218,000)	(262,000)	-
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	15,190	(217,149)	52,862
Fuel, Materials and Supplies	15,850	(4,899)	(18,215)
Interest Accrued	(8,009)	27,490	(2,502)
Accounts Payable	55,772	(6,167)	(55,311)
Taxes Accrued	42,227	(58,721)	27,986
Fuel Recovery	-	16,455	179,866
Change in Other Assets	30,341	(534)	13,276
Change in Other Liabilities	19,330	56,024	11,163
Net Cash Flows From Operating Activities	<u>367,223</u>	<u>147,493</u>	<u>469,920</u>
INVESTING ACTIVITIES			
Construction Expenditures	(141,771)	(151,645)	(193,732)
Other	7,455	143	(354)
Net Cash Flows Used For Investing Activities	<u>(134,316)</u>	<u>(151,502)</u>	<u>(194,086)</u>
FINANCING ACTIVITIES			
Change in Short-term Debt - Affiliates	(650,000)	650,000	-
Issuance of Long-term Debt	953,136	797,335	260,162
Retirement of Long-term Debt	(247,127)	(639,492)	(475,606)
Change in Advances to/from Affiliates, Net	(187,410)	(227,566)	84,565
Retirement of Common Stock	-	(386,005)	-
Retirement of Preferred Stock	(2)	(6)	-
Dividends Paid on Common Stock	(120,801)	(115,505)	(148,057)
Dividends Paid on Cumulative Preferred Stock	(241)	(241)	(242)
Net Cash Flows From (Used For) Financing Activities	<u>(252,445)</u>	<u>78,520</u>	<u>(279,178)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	(19,538)	74,511	(3,344)
Cash and Cash Equivalents at Beginning of Period	<u>85,420</u>	<u>10,909</u>	<u>14,253</u>
Cash and Cash Equivalents at End of Period	<u>\$65,882</u>	<u>\$85,420</u>	<u>\$10,909</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$129,491,000, \$93,120,000 and \$109,835,000 and for income taxes was \$49,630,000, \$95,600,000 and \$161,529,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						<u>2003</u>	<u>2002</u>
						(in thousands)	
TOTAL COMMON SHAREHOLDER'S EQUITY (a)						<u>\$1,209,049</u>	<u>\$1,101,134</u>
PREFERRED STOCK – 3,035,000 authorized shares, \$100 par value							
Not Subject to Mandatory Redemption:							
<u>Series</u>	<u>Call Price</u> <u>December 31,</u> <u>2003</u>	<u>Number of Shares Redeemed</u> <u>Year Ended December 31,</u>			<u>Shares</u> <u>Outstanding</u> <u>December 31,</u> <u>2003</u>		
		<u>2003</u>	<u>2002</u>	<u>2001</u>			
4.00%	\$105.75	11	100	-	41,927	4,192	4,194
4.20%	103.75	-	-	-	17,476	<u>1,748</u>	<u>1,748</u>
Total Preferred Stock						<u>5,940</u>	<u>5,942</u>
TRUST PREFERRED SECURITIES:							
TCC-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of TCC, 8.00%, due April 30, 2037 (b)							
						<u>-</u>	<u>136,250</u>
LONG-TERM (See Schedule of Long-term Debt):							
First Mortgage Bonds						117,939	152,353
Securitization Bonds (a)						745,680	796,635
Note Payable to Trust (b)						140,889	-
Installment Purchase Contracts						489,585	489,577
Senior Unsecured Notes						797,532	-
Less Portion Due Within One year						<u>(237,651)</u>	<u>(229,131)</u>
Long-term Debt Excluding Portion Due Within One Year						<u>2,053,974</u>	<u>1,209,434</u>
TOTAL CAPITALIZATION						<u>\$3,268,963</u>	<u>\$2,452,760</u>

(a) In February 2002, TCC issued securitization bonds. \$386 million of the proceeds was used to retire 4,543,857 shares of common stock.

(b) See Note 16 for discussion of Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
6.875	2003 – February 1	\$-	\$16,418
7.25	2004 – October 1	27,400	27,400
7-1/8	2008 – February 1	18,581	18,581
7.50	2023 – April 1	-	17,996
6-5/8	2005 – July 1	<u>71,958</u>	<u>71,958</u>
Total		<u><u>\$117,939</u></u>	<u><u>\$152,353</u></u>

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains 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.

Securitization Bonds outstanding were as follows:

<u>%Rate</u>	<u>Final Payment Date</u>	<u>Maturity Date</u>	<u>2003</u>	<u>2002</u>
			<u>(in thousands)</u>	
3.54	1/15/2005	1/15/2007	\$77,937	\$128,950
5.01	1/15/2008	1/15/2010	154,507	154,507
5.56	1/15/2010	1/15/2012	107,094	107,094
5.96	7/15/2013	7/15/2015	214,927	214,927
6.25	1/15/2016	1/15/2017	191,857	191,857
Unamortized Discount			<u>(642)</u>	<u>(700)</u>
Total			<u><u>\$745,680</u></u>	<u><u>\$796,635</u></u>

In February 2002, CPL Transition Funding LLC, a special purpose subsidiary of TCC, issued \$797 million of Securitization Bonds, Series 2002-1. The Securitization Bonds mature at different times through 2017 and have a weighted average interest rate of 5.4 percent.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
5.50	2013 – February 15	\$275,000	\$-
6.65	2033 – February 15	275,000	-
3.00	2005 – February 15	150,000	-
(a)	2005 – February 15	100,000	-
Unamortized Discount		<u>(2,468)</u>	<u>-</u>
Total		<u><u>\$797,532</u></u>	<u><u>\$-</u></u>

(a) A floating interest rate is determined quarterly. The rate on December 31, 2003 was 2.43%.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
Matagorda County Navigation District, Texas:			
6.00	2028 – July 1	\$120,265	\$120,265
6-1/8	2030 – May 1	60,000	60,000
3.75	2003 – November 1	-	111,700
2.15	2030 – May 1 (a)	111,700	-
4.00	2030 – May 1	-	50,000
4.55	2029 – November 1 (b)	100,635	100,635
2.35	2030 – May 1 (a)	50,000	-
Guadalupe-Blanco River Authority District, Texas:			
	2015 – November 1 (c)	40,890	40,890
Red River Authority of Texas:			
6.00	2020 – June 1	6,330	6,330
	Unamortized Discount	(235)	(243)
Total		<u>\$489,585</u>	<u>\$489,577</u>

- (a) Installment Purchase Contract provides for bonds to be tendered in 2004 for 2.15% and 2.35% series. Therefore, these installment purchase contracts have been classified for payment in 2004.
- (b) Installment Purchase Contract provides for bonds to be tendered in 2006 for 4.55% series. Therefore, this installment purchase contract has been classified for payment in 2006.
- (c) A floating interest rate is determined daily. The rate on December 31, 2003 was 1.30%.

Under the terms of the installment purchase contracts, TCC is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Notes Payable to Trust was outstanding as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
8.00	2037 – April 30	<u>\$140,889</u>	<u>\$-</u>

See Note 16 for discussion of Notes Payable to Trust.

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$237,651
2005	371,938
2006	152,900
2007	52,729
2008	68,688
Later Years	<u>1,411,064</u>
Total Principal Amount	2,294,970
Unamortized Discount	<u>(3,345)</u>
Total	<u>\$2,291,625</u>

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to TCC's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to TCC. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19
Subsequent Events (Unaudited)	Note 20

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of AEP Texas Central Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of AEP Texas Central Company and subsidiary as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 AEP Texas Central Company and subsidiary as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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 2 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
March 5, 2004

AEP TEXAS NORTH COMPANY

**AEP TEXAS NORTH COMPANY
SELECTED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$465,946	\$450,740	\$556,458	\$571,064	\$445,709
Operating Expenses	<u>397,919</u>	<u>442,869</u>	<u>523,068</u>	<u>518,723</u>	<u>391,910</u>
Operating Income	68,027	7,871	33,390	52,341	53,799
Nonoperating Items, Net	9,685	(703)	2,195	(1,675)	2,488
Interest Charges	<u>22,049</u>	<u>20,845</u>	<u>23,275</u>	<u>23,216</u>	<u>24,420</u>
Income (Loss) Before Extraordinary Item and Cumulative Effect of					
Accounting Change	<u>55,663</u>	<u>(13,677)</u>	<u>12,310</u>	<u>27,450</u>	<u>31,867</u>
Extraordinary Loss	(177)	-	-	-	(5,461)
Cumulative Effect of Accounting Change	<u>3,071</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income (Loss)	58,557	(13,677)	12,310	27,450	26,406
Gain on Reacquired Preferred Stock	3	-	-	-	-
Preferred Stock Dividend Requirements	<u>104</u>	<u>104</u>	<u>104</u>	<u>104</u>	<u>104</u>
Earnings (Loss) Applicable to Common Stock	<u>\$58,456</u>	<u>\$(13,781)</u>	<u>\$12,206</u>	<u>\$27,346</u>	<u>\$ 26,302</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$1,233,427	\$1,201,747	\$1,260,872	\$1,229,339	\$1,182,544
Accumulated Depreciation and Amortization	<u>460,513</u>	<u>446,818</u>	<u>475,036</u>	<u>447,802</u>	<u>446,282</u>
Net Electric Utility Plant	<u>\$772,914</u>	<u>\$754,929</u>	<u>\$785,836</u>	<u>\$781,537</u>	<u>\$736,262</u>
TOTAL ASSETS	<u>\$1,009,509</u>	<u>\$952,149</u>	<u>\$936,001</u>	<u>\$1,154,743</u>	<u>\$910,770</u>
Common Stock and Paid-in Capital	\$139,565	\$139,565	\$139,565	\$139,565	\$139,565
Retained Earnings	125,428	71,942	105,970	122,588	113,242
Accumulated Other Comprehensive Income (Loss)	<u>(26,718)</u>	<u>(30,763)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u>\$238,275</u>	<u>\$180,744</u>	<u>\$245,535</u>	<u>\$262,153</u>	<u>\$252,807</u>
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>\$2,357</u>	<u>\$2,367</u>	<u>\$2,367</u>	<u>\$2,367</u>	<u>\$2,367</u>
Long-term Debt (a)	<u>\$356,754</u>	<u>\$132,500</u>	<u>\$255,967</u>	<u>\$255,843</u>	<u>\$303,686</u>
Obligations Under Capital Leases (a)	<u>\$473</u>	<u>\$-</u>	<u>\$-</u>	<u>\$-</u>	<u>\$-</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$1,009,509</u>	<u>\$952,149</u>	<u>\$936,001</u>	<u>\$1,154,743</u>	<u>\$910,770</u>

(a) Including portion due within one year.

AEP TEXAS NORTH COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEP Texas North Company (TNC), formerly known as West Texas Utilities Company (WTU), is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power in west and central Texas. 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. TNC also sells electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members 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 revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

Net Income increased \$72 million primarily due to a 2002 \$43 million write-down (\$28 million after tax) of gas power plants and increased risk management margins of \$20 million in 2003. Transactions with ERCOT also significantly increased income in 2003.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a significant shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy WTU to an unrelated third party, who assumed the obligations of the affiliated REP, including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy WTU were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy WTU are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income increased by \$60 million primarily due to:

- The 2002 asset impairment of \$43 million. See Note 10 “Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used.”
- Increased Reliability Must Run (RMR) revenues from ERCOT of \$44 million which include both fuel recovery and a fixed cost component of \$13 million (see “Texas Plants” in Note 10 for discussion of RMR facilities).
- Increased revenues from risk management activities of \$10 million.
- Increased revenues from ERCOT of \$22 million or 91% for various services, due mainly to prior years adjustments made by ERCOT.
- Decreased fuel and purchased power on a net basis of \$9 million. KWH generation decreased 27% mainly due to mothballing of plants while the per unit cost of fuel increased 14% due primarily to higher natural gas prices. KWH purchased declined 9%, but the average cost increased 2%.
- Reduced Other Operation expenses of \$20 million due to several factors including \$8 million of customer service, outside services, other administrative related expenses, ERCOT transmission charges of \$4 million, distribution expenses of \$2 million, and a \$2 million write-down of material and supplies to market value related to the deactivation of several power plants in 2002.
- Decreased Maintenance expense of \$3 million due primarily to the deactivation of several power plants in 2002 (See Note 10).
- Reduced Depreciation and Amortization of \$7 million due to the 2002 impairment of several power plants resulting in approximately \$4 million less depreciation expense. An additional decrease of \$3 million relates to adjustments to prior years’ excess earnings accruals under the Texas restructuring legislation due to a favorable Appeals Court ruling (See Note 6).
- Decrease of Taxes Other Than Income Taxes of \$2 million is due to reduced gross receipts tax as a result of the sale of the Texas REPs.

The increase in Operating Income was partially offset by:

- Decreased system sales, including those to REP’s, of \$7 million due mainly to both lower KWH sales of 17% and a decrease in the overall average price per KWH.
- The 2002 ICR adjustments decreased revenue by approximately \$24 million in 2003. This decrease was partially offset by a reduction in purchased power, due to these adjustments of \$5 million.
- Decreased delivery revenues of \$5 million, due partly to decreased cooling and heating degree-days.
- Reduced wholesale revenues of \$8 million due to the loss of several large wholesale customers whose contracts expired and were not renewed.
- Increased provision for rate refunds of \$20 million in 2003 due mainly to the final Texas fuel reconciliation (see “TNC Fuel Reconciliation” in Note 4).
- Increased Federal Income Taxes of \$39 million due to the increase in pre-tax operating income.

Other Impacts on Earnings

Nonoperating Income increased \$15 million primarily due to a \$10 million increase in net revenue from risk management activities, while revenue from third party non-utility energy related construction projects increased \$5 million.

Extraordinary (Loss) – (Net of Tax)

Extraordinary loss resulted from the cessation of SFAS 71 accounting for wholesale generation assets due to the FERC settlement case (see Note 2).

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. TNC had its secured debt downgraded from A2 to A3 and unsecured debt downgraded from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and mortgage bonds ratings from BBB+ to BBB.

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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period (in thousands)				
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Long-term Debt	\$42,505	\$37,609	\$8,151	\$268,489	\$356,754
Unconditional Purchase Obligations (a)	51,172	82,478	57,456	201,096	392,202
Capital Lease Obligations	223	275	9	2	509
Noncancellable Operating Leases	<u>1,964</u>	<u>3,791</u>	<u>2,770</u>	<u>4,981</u>	<u>13,506</u>
Total	<u>\$95,864</u>	<u>\$124,153</u>	<u>\$68,386</u>	<u>\$474,568</u>	<u>\$762,971</u>

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

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 and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

<u>Other Commercial Commitments</u>	Amount of Commitment Expiration Per Period (in thousands)				
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Transmission Facilities for Third Parties (a)	\$75,658	\$15,621	\$-	\$-	\$91,279

(a) 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.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effects.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$2,043
(Gain) Loss from Contracts Realized/Settled During the Period (a)	104
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(110)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	20
Changes in Fair Value of Risk Management Contracts (e)	3,203
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(640)
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	4,620
Net Cash Flow Hedge Contracts (g)	(926)
Ending Balance December 31, 2003	<u>\$3,694</u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b)The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d)See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actually Quoted – Exchange Traded Contracts	\$96	\$(40)	\$4	\$24	\$-	\$-	\$84
Prices Provided by Other External Sources – OTC Broker Quotes (a)	932	631	231	146	84	-	2,024
Prices Based on Models and Other Valuation Methods (b)	<u>1,323</u>	<u>223</u>	<u>45</u>	<u>95</u>	<u>199</u>	<u>627</u>	<u>2,512</u>
Total	<u>\$2,351</u>	<u>\$814</u>	<u>\$280</u>	<u>\$265</u>	<u>\$283</u>	<u>\$627</u>	<u>\$4,620</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$(15)
Changes in Fair Value (a)	(641)
Reclassifications from AOCI to Net Income (b)	<u>55</u>
Ending Balance December 31, 2003	<u>\$(601)</u>

- (a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
- (b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$435 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$76	\$294	\$123	\$29	\$48	\$146	\$52	\$11

VaR Associated with Debt Outstanding

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 \$33 million and \$5 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$410,793	\$210,315	\$537,777
Sales to AEP Affiliates	<u>55,153</u>	<u>240,425</u>	<u>18,681</u>
TOTAL	<u>465,946</u>	<u>450,740</u>	<u>556,458</u>
OPERATING EXPENSES			
Fuel for Electric Generation	39,082	36,081	177,140
Fuel from Affiliates for Electric Generation	44,197	64,385	-
Purchased Electricity for Resale	87,006	80,391	70,395
Purchased Electricity from AEP Affiliates	39,409	37,582	56,656
Other Operation	85,263	104,960	111,248
Asset Impairments	-	42,898	-
Maintenance	18,961	22,295	22,343
Depreciation and Amortization	36,242	43,620	50,705
Taxes Other Than Income Taxes	20,570	22,471	28,319
Income Tax Expense (Credit)	<u>27,189</u>	<u>(11,814)</u>	<u>6,262</u>
TOTAL	<u>397,919</u>	<u>442,869</u>	<u>523,068</u>
OPERATING INCOME	68,027	7,871	33,390
Nonoperating Income	68,451	53,884	12,199
Nonoperating Expenses	55,692	54,876	10,695
Nonoperating Income Tax Expense (Credit)	3,074	(289)	(691)
Interest Charges	<u>22,049</u>	<u>20,845</u>	<u>23,275</u>
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,663	(13,677)	12,310
Extraordinary (Loss) – (Net of Tax)	(177)	-	-
Cumulative Effect of Accounting Changes (Net of Tax)	<u>3,071</u>	<u>-</u>	<u>-</u>
NET INCOME (LOSS)	58,557	(13,677)	12,310
Gain on Reacquired Preferred Stock	3	-	-
Preferred Stock Dividend Requirements	<u>104</u>	<u>104</u>	<u>104</u>
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	<u>\$58,456</u>	<u>\$(13,781)</u>	<u>\$12,206</u>

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$137,214	\$2,351	\$122,588	\$-	\$262,153
Common Stock Dividends Declared			(28,824)		(28,824)
Preferred Stock Dividends Declared			(104)		(104)
TOTAL					<u>233,225</u>
COMPREHENSIVE INCOME					
NET INCOME			12,310		<u>12,310</u>
TOTAL COMPREHENSIVE INCOME					<u>12,310</u>
DECEMBER 31, 2001	\$137,214	\$2,351	\$105,970	\$-	\$245,535
Common Stock Dividends			(20,247)		(20,247)
Preferred Stock Dividends			(104)		(104)
TOTAL					<u>225,184</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(15)	(15)
Minimum Pension Liability				(30,748)	(30,748)
NET INCOME (LOSS)			(13,677)		<u>(13,677)</u>
TOTAL COMPREHENSIVE INCOME					<u>(44,440)</u>
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					<u>175,673</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(586)	(586)
Minimum Pension Liability				4,631	4,631
NET INCOME			58,557		<u>58,557</u>
TOTAL COMPREHENSIVE INCOME					<u>62,602</u>
DECEMBER 31, 2003	<u>\$137,214</u>	<u>\$2,351</u>	<u>\$125,428</u>	<u>\$(26,718)</u>	<u>\$238,275</u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and December 31, 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	\$360,463	\$353,087
Transmission	268,695	254,483
Distribution	456,278	445,486
General	117,792	111,679
Construction Work in Progress	30,199	37,012
TOTAL	<u>1,233,427</u>	<u>1,201,747</u>
Accumulated Depreciation and Amortization	<u>460,513</u>	<u>446,818</u>
TOTAL – NET	<u>772,914</u>	<u>754,929</u>
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,286	1,086
Other Investments	-	127
TOTAL	<u>1,286</u>	<u>1,213</u>
CURRENT ASSETS		
Cash and Cash Equivalents	2,863	1,219
Advances to Affiliates	41,593	-
Accounts Receivable:		
Customers	56,670	62,646
Affiliated Companies	28,910	43,632
Accrued Unbilled Revenues	4,871	6,829
Miscellaneous	3,411	14
Allowance for Uncollectible Accounts	(175)	(5,041)
Fuel Inventory	10,925	12,677
Materials and Supplies	8,866	9,574
Risk Management Assets	10,340	4,130
Margin Deposits	1,285	37
Prepayments and Other	1,834	1,033
TOTAL	<u>171,393</u>	<u>136,750</u>
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Fuel Costs	26,680	26,680
Deferred Debt – Restructuring	6,579	10,134
Unamortized Loss on Reacquired Debt	3,929	3,283
Other	3,332	5,000
Long-term Risk Management Assets	3,106	2,248
Deferred Charges	20,290	11,912
TOTAL	<u>63,916</u>	<u>59,257</u>
TOTAL ASSETS	<u>\$1,009,509</u>	<u>\$952,149</u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
<u>CAPITALIZATION</u>		
Common Shareholder's Equity:		
Common Stock – \$25 Par Value:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	\$137,214	\$137,214
Paid-in Capital	2,351	2,351
Retained Earnings	125,428	71,942
Accumulated Other Comprehensive Income (Loss)	<u>(26,718)</u>	<u>(30,763)</u>
Total Common Shareholder's Equity	238,275	180,744
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>2,357</u>	<u>2,367</u>
Total Shareholder's Equity	240,632	183,111
Long-term Debt	<u>314,249</u>	<u>132,500</u>
TOTAL	<u>554,881</u>	<u>315,611</u>
<u>CURRENT LIABILITIES</u>		
Short-term Debt – Affiliates	-	125,000
Long-term Debt Due Within One Year	42,505	-
Advances from Affiliates	-	80,407
Accounts Payable:		
General	28,190	32,714
Affiliated Companies	40,601	76,217
Customer Deposits	161	117
Taxes Accrued	22,877	3,697
Interest Accrued	6,038	2,776
Risk Management Liabilities	8,658	3,801
Obligations Under Capital Leases	203	-
Other	<u>9,419</u>	<u>17,414</u>
TOTAL	<u>158,652</u>	<u>342,143</u>
<u>DEFERRED CREDITS AND OTHER LIABILITIES</u>		
Deferred Income Taxes	113,019	117,521
Long-term Risk Management Liabilities	1,094	557
Regulatory Liabilities:		
Asset Removal Costs	76,740	-
Deferred Investment Tax Credits	19,990	21,510
Retail Clawback	11,804	14,328
Excess Earnings	14,262	17,419
SFAS 109 Regulatory Liability, Net	13,655	12,280
Other	1,826	7,285
Obligations Under Capital Leases	270	-
Deferred Credits and Other	<u>43,316</u>	<u>103,495</u>
TOTAL	<u>295,976</u>	<u>294,395</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$1,009,509</u>	<u>\$952,149</u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	\$58,557	\$(13,677)	\$12,310
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Depreciation and Amortization	36,242	43,620	50,705
Extraordinary (Loss) – Net of Tax	177	-	-
Write Down of Utility Plant Assets	-	38,154	-
Write Down of Wind Farm Assets	-	4,744	-
Deferred Income Taxes	(3,493)	(12,275)	(11,891)
Deferred Investment Tax Credits	(1,520)	(1,271)	(1,271)
Cumulative Effect of Accounting Changes	(3,071)	-	-
Mark-to-Market of Risk Management Contracts	(2,558)	(1,127)	(3,506)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	14,393	(80,900)	24,844
Fuel, Materials and Supplies	2,460	(2,754)	3,187
Accounts Payable	(40,140)	63,761	(42,604)
Taxes Accrued	19,180	(13,661)	(1,543)
Fuel Recovery	-	14,169	32,505
Change in Other Assets	(8,955)	(16,928)	(1,432)
Change in Other Liabilities	5,996	16,514	11,056
Net Cash Flows From Operating Activities	<u>77,268</u>	<u>38,369</u>	<u>72,360</u>
INVESTING ACTIVITIES			
Construction Expenditures	(46,683)	(43,563)	(39,662)
Other	688	150	(127)
Net Cash Flows Used For Investing Activities	<u>(45,995)</u>	<u>(43,413)</u>	<u>(39,789)</u>
FINANCING ACTIVITIES			
Change in Short-term Debt - Affiliates	(125,000)	125,000	-
Issuance of Long-term Debt	222,455	-	-
Retirement of Long-term Debt	-	(130,799)	-
Retirement of Preferred Stock	(10)	-	-
Change in Advances to/from Affiliates, Net	(122,000)	29,959	(8,130)
Dividends Paid on Common Stock	(4,970)	(20,247)	(28,824)
Dividends Paid on Cumulative Preferred Stock	(104)	(104)	(104)
Net Cash Flows From (Used For) Financing Activities	<u>(29,629)</u>	<u>3,809</u>	<u>(37,058)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	1,644	(1,235)	(4,487)
Cash and Cash Equivalents at Beginning of Period	<u>1,219</u>	<u>2,454</u>	<u>6,941</u>
Cash and Cash Equivalents at End of Period	<u>\$2,863</u>	<u>\$1,219</u>	<u>\$2,454</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$16,384,000, \$19,934,000 and \$19,279,000 and for income taxes was \$16,081,000, \$15,544,000 and \$21,997,000 in 2003, 2002 and 2001 respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						<u>2003</u>	<u>2002</u>
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						<u>\$238,275</u>	<u>\$180,744</u>
PREFERRED STOCK: \$100 par value – authorized shares 810,000							
<u>Series</u>	<u>Call Price</u> <u>December 31,</u> <u>2003</u>	<u>Number of Shares Redeemed</u> <u>Year Ended December 31,</u>			<u>Shares</u> <u>Outstanding</u> <u>December 31,</u> <u>2003</u>		
		<u>2003</u>	<u>2002</u>	<u>2001</u>			
Not Subject to Mandatory Redemption:							
4.40%	\$107	102	-	-	23,570	<u>2,357</u>	<u>2,367</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						88,236	88,190
Installment Purchase Contracts						44,310	44,310
Senior Unsecured Notes						224,208	-
Less Portion Due Within One Year						<u>(42,505)</u>	<u>-</u>
Long-term Debt Excluding Portion Due Within One Year						<u>314,249</u>	<u>132,500</u>
TOTAL CAPITALIZATION						<u>\$554,881</u>	<u>\$315,611</u>

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
7.00	2004 – October 1	\$18,469	\$18,469
6-1/8	2004 – February 1	24,036	24,036
6-3/8	2005 – October 1	37,609	37,609
7-3/4	2007 – June 1	8,151	8,151
	Unamortized Discount	<u>(29)</u>	<u>(75)</u>
Total		<u>\$88,236</u>	<u>\$88,190</u>

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains 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.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
Red River Authority of Texas:			
6.00	2020 – June 1	<u>\$44,310</u>	<u>\$44,310</u>

Under the terms of the Installment Purchase Contracts, TNC 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. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
5.50	2013 – March 1	\$225,000	\$-
	Unamortized Discount	<u>(792)</u>	<u>-</u>
Total		<u>\$224,208</u>	<u>\$-</u>

At December 31, 2003, future annual Long-term Debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$42,505
2005	37,609
2006	-
2007	8,151
2008	-
Later Years	<u>269,310</u>
Total Principal Amount	357,575
Unamortized Discount	<u>(821)</u>
Total	<u>\$356,754</u>

AEP TEXAS NORTH COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to TNC's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to TNC. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of AEP Texas North Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Texas North Company as of December 31, 2003 and 2002, and the related statements of operations, changes in common shareholder's equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 financial statements present fairly, in all material respects, the financial position of AEP Texas North Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

**APPALACHIAN POWER COMPANY
AND SUBSIDIARIES**

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,957,358	\$1,814,470	\$1,784,259	\$1,759,253	\$1,586,050
Operating Expenses	<u>1,638,547</u>	<u>1,512,407</u>	<u>1,509,273</u>	<u>1,558,099</u>	<u>1,344,814</u>
Operating Income	318,811	302,063	274,986	201,154	241,236
Nonoperating Items, Net	(826)	20,106	6,868	11,752	8,096
Interest Charges	<u>115,202</u>	<u>116,677</u>	<u>120,036</u>	<u>148,000</u>	<u>128,840</u>
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	202,783	205,492	161,818	64,906	120,492
Extraordinary Gain	<u>-</u>	<u>-</u>	<u>-</u>	<u>8,938</u>	<u>-</u>
Income Before Cumulative Effect of Accounting Changes	202,783	205,492	161,818	73,844	120,492
Cumulative Effect of Accounting Changes (Net of Tax)	<u>77,257</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	280,040	205,492	161,818	73,844	120,492
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	<u>3,495</u>	<u>2,898</u>	<u>2,011</u>	<u>2,504</u>	<u>2,706</u>
Earnings Applicable to Common Stock	<u><u>\$276,545</u></u>	<u><u>\$202,594</u></u>	<u><u>\$159,807</u></u>	<u><u>\$71,340</u></u>	<u><u>\$117,786</u></u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$6,140,931	\$5,895,303	\$5,664,657	\$5,418,278	\$5,262,951
Accumulated Depreciation and Amortization	<u>2,321,360</u>	<u>2,330,012</u>	<u>2,207,072</u>	<u>2,103,471</u>	<u>1,998,112</u>
Net Electric Utility Plant	<u><u>\$3,819,571</u></u>	<u><u>\$3,565,291</u></u>	<u><u>\$3,457,585</u></u>	<u><u>\$3,314,807</u></u>	<u><u>\$3,264,839</u></u>
TOTAL ASSETS	<u><u>\$4,977,011</u></u>	<u><u>\$4,722,442</u></u>	<u><u>\$4,572,194</u></u>	<u><u>\$6,657,920</u></u>	<u><u>\$4,433,597</u></u>
Common Stock and Paid-in Capital	\$980,357	\$977,700	\$976,244	\$975,676	\$974,717
Retained Earnings	408,718	260,439	150,797	120,584	175,854
Accumulated Other Comprehensive Income (Loss)	<u>(52,088)</u>	<u>(72,082)</u>	<u>(340)</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u><u>\$1,336,987</u></u>	<u><u>\$1,166,057</u></u>	<u><u>\$1,126,701</u></u>	<u><u>\$1,096,260</u></u>	<u><u>\$1,150,571</u></u>
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	\$17,784	\$17,790	\$17,790	\$17,790	\$18,491
Subject to Mandatory Redemption	<u>5,360</u>	<u>10,860</u>	<u>10,860</u>	<u>10,860</u>	<u>20,310</u>
Total Cumulative Preferred Stock	<u><u>\$23,144</u></u>	<u><u>\$28,650</u></u>	<u><u>\$28,650</u></u>	<u><u>\$28,650</u></u>	<u><u>\$38,801</u></u>
Long-term Debt (a)	<u><u>\$1,864,081</u></u>	<u><u>\$1,893,861</u></u>	<u><u>\$1,556,559</u></u>	<u><u>\$1,605,818</u></u>	<u><u>\$1,665,307</u></u>
Obligations Under Capital Leases (a)	<u><u>\$25,352</u></u>	<u><u>\$33,589</u></u>	<u><u>\$46,285</u></u>	<u><u>\$63,160</u></u>	<u><u>\$64,645</u></u>
TOTAL CAPITALIZATION AND LIABILITIES	<u><u>\$4,977,011</u></u>	<u><u>\$4,722,442</u></u>	<u><u>\$4,572,194</u></u>	<u><u>\$6,657,920</u></u>	<u><u>\$4,433,597</u></u>

(a) Including portion due within one year.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES **MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS**

APCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 929,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. 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 their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. 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. In 2003 our relative share of the AEP Power Pool revenues and expenses increased over the prior period as a result of our reaching a new peak demand in January 2003, which increased our allocation factor.

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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

Net Income for 2003 increased \$75 million over the prior year period primarily due to the Cumulative Effect of Accounting Changes of \$77 million recorded in 2003. See "Cumulative Effect of Accounting Changes" in Note 2 for further information.

Income Before Cumulative Effect of Accounting Changes decreased slightly from 2002 as improvements in Operating Income were offset by reduced gains from risk management activities included in Nonoperating Income (Expense). The improvement in Operating Income was driven by increased earnings on system sales and reduced employee related expenses partially offset by increased capacity charges included in Purchased Electricity from AEP Affiliates.

2003 Compared to 2002

Operating Income

Operating Income for 2003 increased by \$17 million from 2002 primarily due to the following:

- An increase in system sales and transmission revenues totaling \$93 million reflecting an increase in the volume of AEP Power Pool transactions, as well as our relative share based on the higher MLR.
- An increase of \$36 million in Sales to AEP Affiliates due to strong wholesale sales by the AEP Power Pool.
- A decrease in Other Operation expense of \$24 million due to severance expenses of \$13 million incurred in 2002 related to the SEI initiative (see Note 9, "Sustained Earnings Improvement Initiative"), as well as reduced employee related expenses and insurance premiums in 2003. These decreases were partially offset by an increase in transmission equalization charges due to the increase in APCo's MLR as described above.

- A decrease in Depreciation and Amortization expense of \$14 million primarily due to reduced amortization of generation related regulatory assets due to the return to SFAS 71 for the West Virginia jurisdiction in the first quarter of 2003 (see Note 5, “Effects of Regulation”).
- An increase in gains from risk management activities of \$10 million.

The increase in Operating Income for 2003 was partially offset by:

- An increase in purchased power expenses and fuel expense of \$150 million reflecting the \$62 million increase in capacity charges resulting from the increase in APCo’s MLR as described above, the increase in our relative share of the AEP Power Pool expenses and increased generation. Also, we accrued additional fuel expense to increase fuel costs to match fuel revenues billed to ratepayers (see “Deferred Fuel Costs” in Note 1, “Summary of Significant Accounting Policies”).
- An increase in Maintenance expense of \$13 million primarily due to increased maintenance of overhead lines required due to severe storm damage in the first quarter of 2003 and increased overhead line maintenance throughout the year.

Other Impacts on Earnings

Nonoperating income decreased \$36 million in 2003 compared to 2002 primarily due to lower profit from power sold outside AEP’s traditional marketing area resulting from AEP’s plan to exit risk management activities in areas outside of its traditional market area. The decrease in nonoperating income was partially offset by a \$12 million decrease in nonoperating income taxes resulting primarily from the reduced pre-tax nonoperating book income.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of \$77 million is due to the implementation of SFAS 143 and EITF 02-03 (see “Cumulative Effect” section of Note 2).

2002 Compared to 2001

Net Income

Net Income for 2002 increased \$44 million over the prior year due to higher retail sales resulting from weather related electricity demands and reductions in Maintenance expense. Most significantly the Mountaineer, Amos and Glen Lyn plants, down for boiler maintenance in 2001, were back online in 2002 resulting in increased availability of generation and decreased maintenance expense. In addition, net nonoperating income increased \$10 million as a result of a reduction in incentive compensation partially offset by decreased gains from risk management activities.

Operating Income

Operating Income for 2002 increased \$27 million compared to the prior year primarily due to the following:

- Retail sales increased \$42 million primarily due to weather related electricity demands.
- An increase in Sales to AEP Affiliates of \$15 million due to an increase in generation capacity and power available to be delivered to the AEP Power Pool.
- A decrease of \$10 million in Maintenance expense due to the boiler maintenance incurred in 2001 as discussed above.
- A \$97 million decrease in purchase power expense resulting from increased internal generation based on the higher plant availability partially offset by a \$79 million increase in Fuel expense necessary to support the increased generation.
- A \$5 million decrease in Taxes Other Than Income Taxes primarily due to the replacement of the municipal license tax imposed on APCo with the Virginia consumption tax that was imposed on the consumer.

These increases in Operating Income for 2002 were offset by:

- A net \$32 million decrease in system sales partially offset by gains from risk management activities.
- An increase of \$9 million in Other Operation expense mainly due to \$13 million of severance expenses related to the SEI initiative, a reduction in gains recorded on the dispositions of SO2 emission allowances and increased insurance premiums and other employee benefit costs.
- An increase of \$9 million in Depreciation and Amortization due to increased amortization for the net generation-related regulatory assets related to our West Virginia jurisdiction which were assigned to the distribution portion of our business and are being recovered through regulated rates.
- An increase of \$18 million in Income Taxes due to an increase in pre-tax income.

Other Impacts on Earnings

Nonoperating income decreased \$20 million for 2002, primarily due to a decrease in gains from risk management activities driven by a decline in market prices. Nonoperating Expenses decreased \$30 million due to decreased incentives related to risk management activities.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from Baa1 to Baa2 and a downgrade of secured ratings from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows for 2003, 2002 and 2001 were as follows:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
Cash and cash equivalents at beginning of period	<u>\$4,285</u>	<u>\$13,663</u>	<u>\$5,847</u>
Cash flow from (used for):			
Operating activities	461,276	280,709	393,854
Investing activities	(286,608)	(275,475)	(313,298)
Financing activities	<u>(133,072)</u>	<u>(14,612)</u>	<u>(72,740)</u>
Net increase (decrease) in cash and cash equivalents	<u>41,596</u>	<u>(9,378)</u>	<u>7,816</u>
Cash and cash equivalents at end of period	<u><u>\$45,881</u></u>	<u><u>\$4,285</u></u>	<u><u>\$13,663</u></u>

Operating Activities

Cash flow from operating activities in 2003 increased \$181 million over the prior year primarily due to decreases in various accounts receivable balances in 2003 and changes in Federal and state income tax accruals.

Investing Activities

Construction expenditures in 2003 versus 2002 increased \$12 million. The current year expenditures of \$289 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Financing Activities

In 2003, we issued two series of Senior Unsecured Notes, each in the amount of \$200 million which were used to call First Mortgage Bonds and Senior Unsecured Notes and fund maturities. Additionally, we incurred obligations of \$188 million in Installment Purchase Contracts to redeem higher costing Installment Purchase Contracts.

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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$161,008	\$677,521	\$400,027	\$625,525	\$1,864,081
Advances from Affiliates	82,994	-	-	-	82,994
Preferred Stock Subject to Mandatory Redemption	-	-	5,360	-	5,360
Capital Lease Obligations	11,735	12,036	5,309	1,802	30,882
Unconditional Purchase Obligations (a)	311,826	351,760	90,163	-	753,749
Noncancellable Operating Leases	<u>5,998</u>	<u>9,609</u>	<u>5,696</u>	<u>6,094</u>	<u>27,397</u>
Total	<u>\$573,561</u>	<u>\$1,050,926</u>	<u>\$506,555</u>	<u>\$633,421</u>	<u>\$2,764,463</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$96,852
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(33,846)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	143
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,664)
Changes in Fair Value of Risk Management Contracts (e)	9,305
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	276
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	68,066
Net Cash Flow Hedge Contracts (g)	553
DETM Assignment (h)	(32,287)
Ending Balance December 31, 2003	<u>\$36,332</u>

- (a) “(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c) “Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e) “Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f) “Change in Fair Value of Risk Management Contracts 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.
- (g) “Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
- (h) See Note 17 “Related Party Transactions.”

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003**

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actively Quoted – Exchange Traded Contracts	\$1,219	\$(245)	\$29	\$191	\$-	\$-	\$1,194
Prices Provided by Other External Sources – OTC Broker Quotes (a)	23,753	8,514	8,350	3,395	1,703	-	45,715
Prices Based on Models and Other Valuation Methods (b)	<u>(7)</u>	<u>36</u>	<u>3,313</u>	<u>3,829</u>	<u>3,521</u>	<u>10,465</u>	<u>21,157</u>
Total	<u>\$24,965</u>	<u>\$8,305</u>	<u>\$11,692</u>	<u>\$7,415</u>	<u>\$5,224</u>	<u>\$10,465</u>	<u>\$68,066</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

**Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003**

	<u>Domestic Power</u>	<u>Foreign Currency</u>	<u>Interest Rate</u>	<u>Consolidated</u>
	(in thousands)			
Beginning Balance December 31, 2002	\$(394)	\$(190)	\$(1,336)	\$(1,920)
Changes in Fair Value (a)	272	-	(720)	(448)
Reclassifications from AOCI to Net Income (b)	<u>481</u>	<u>7</u>	<u>311</u>	<u>799</u>
Ending Balance December 31, 2003	<u>\$359</u>	<u>\$(183)</u>	<u>\$(1,745)</u>	<u>\$(1,569)</u>

- (a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.
- (b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$1,325 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$596	\$2,314	\$969	\$230	\$1,289	\$3,948	\$1,412	\$286

VaR Associated with Debt Outstanding

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 \$102 million and \$87 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,734,565	\$1,627,993	\$1,612,974
Sales to AEP Affiliates	<u>222,793</u>	<u>186,477</u>	<u>171,285</u>
TOTAL	<u>1,957,358</u>	<u>1,814,470</u>	<u>1,784,259</u>
OPERATING EXPENSES			
Fuel for Electric Generation	454,901	430,963	351,557
Purchased Electricity for Resale	66,084	57,091	42,092
Purchased Electricity from AEP Affiliates	351,210	234,597	346,878
Other Operation	245,308	269,426	260,518
Maintenance	135,596	122,209	132,373
Depreciation and Amortization	175,772	189,335	180,393
Taxes Other Than Income Taxes	90,087	95,249	99,878
Income Taxes	<u>119,589</u>	<u>113,537</u>	<u>95,584</u>
TOTAL	<u>1,638,547</u>	<u>1,512,407</u>	<u>1,509,273</u>
OPERATING INCOME	318,811	302,063	274,986
Nonoperating Income (Expense)	(5,661)	30,020	50,268
Nonoperating Expenses	9,534	12,525	42,261
Nonoperating Income Tax Expense (Credit)	(14,369)	(2,611)	1,139
Interest Charges	<u>115,202</u>	<u>116,677</u>	<u>120,036</u>
Income Before Cumulative Effect of Accounting Changes	202,783	205,492	161,818
Cumulative Effect of Accounting Changes (Net of Tax)	<u>77,257</u>	<u>-</u>	<u>-</u>
NET INCOME	280,040	205,492	161,818
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	<u>3,495</u>	<u>2,898</u>	<u>2,011</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$276,545</u>	<u>\$202,594</u>	<u>\$159,807</u>

The common stock of APCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$260,458	\$715,218	\$120,584	\$-	\$1,096,260
Common Stock Dividends			(129,594)		(129,594)
Preferred Stock Dividends			(1,443)		(1,443)
Capital Stock Expense		568	(568)		-
TOTAL					<u>965,223</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(340)	(340)
NET INCOME			161,818		<u>161,818</u>
TOTAL COMPREHENSIVE INCOME					<u>161,478</u>
DECEMBER 31, 2001	\$260,458	\$715,786	\$150,797	\$(340)	\$1,126,701
Common Stock Dividends			(92,952)		(92,952)
Preferred Stock Dividends			(1,442)		(1,442)
Capital Stock Expense		1,456	(1,456)		-
TOTAL					<u>1,032,307</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,580)	(1,580)
Minimum Pension Liability				(70,162)	(70,162)
NET INCOME			205,492		<u>205,492</u>
TOTAL COMPREHENSIVE INCOME					<u>133,750</u>
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 Reapplication		163			163
TOTAL					<u>1,036,953</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				351	351
Minimum Pension Liability				19,643	19,643
NET INCOME			280,040		<u>280,040</u>
TOTAL COMPREHENSIVE INCOME					<u>300,034</u>
DECEMBER 31, 2003	<u>\$260,458</u>	<u>\$719,899</u>	<u>\$408,718</u>	<u>\$(52,088)</u>	<u>\$1,336,987</u>

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$2,287,043	\$2,245,945
Transmission	1,240,889	1,218,108
Distribution	2,006,329	1,951,804
General	294,786	272,901
Construction Work in Progress	<u>311,884</u>	<u>206,545</u>
TOTAL	6,140,931	5,895,303
Accumulated Depreciation and Amortization	<u>2,321,360</u>	<u>2,330,012</u>
TOTAL - NET	<u>3,819,571</u>	<u>3,565,291</u>
<u>OTHER PROPERTY AND INVESTMENTS</u>		
Non-Utility Property, Net	20,574	20,550
Other Investments	<u>26,668</u>	<u>34,103</u>
TOTAL	<u>47,242</u>	<u>54,653</u>
<u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	45,881	4,285
Accounts Receivable:		
Customers	133,717	155,521
Affiliated Companies	137,281	122,665
Accrued Unbilled Revenues	35,020	30,948
Miscellaneous	3,961	5,374
Allowance for Uncollectible Accounts	(2,085)	(13,439)
Fuel Inventory	42,806	53,646
Materials and Supplies	71,978	59,886
Risk Management Assets	71,189	94,010
Margin Deposits	11,525	1,238
Prepayments and Other	<u>13,301</u>	<u>12,386</u>
TOTAL	<u>564,574</u>	<u>526,520</u>
<u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
Transition Regulatory Assets	30,855	158,708
SFAS 109 Regulatory Asset, Net	325,889	209,884
Unamortized Loss on Reacquired Debt	19,005	9,147
Other Regulatory Assets	41,447	17,814
Long-term Risk Management Assets	70,900	115,748
Deferred Property Taxes	35,343	35,323
Other Deferred Charges	<u>22,185</u>	<u>29,354</u>
TOTAL	<u>545,624</u>	<u>575,978</u>
TOTAL ASSETS	<u>\$4,977,011</u>	<u>\$4,722,442</u>

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
CAPITALIZATION		
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	719,899	717,242
Retained Earnings	408,718	260,439
Accumulated Other Comprehensive Income (Loss)	<u>(52,088)</u>	<u>(72,082)</u>
Total Common Shareholder's Equity	1,336,987	1,166,057
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>17,784</u>	<u>17,790</u>
Total Shareholder's Equity	1,354,771	1,183,847
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,360	10,860
Long-term Debt	<u>1,703,073</u>	<u>1,738,854</u>
TOTAL	<u>3,063,204</u>	<u>2,933,561</u>
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	161,008	155,007
Advances from Affiliates	82,994	39,205
Accounts Payable:		
General	140,497	141,546
Affiliated Companies	81,812	98,374
Customer Deposits	33,930	26,186
Taxes Accrued	50,259	29,181
Interest Accrued	22,113	22,437
Risk Management Liabilities	51,430	69,001
Obligations Under Capital Leases	9,218	9,598
Other	<u>60,289</u>	<u>70,234</u>
TOTAL	<u>693,550</u>	<u>660,769</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	803,355	701,801
Regulatory Liabilities:		
Asset Removal Costs	92,497	-
Deferred Investment Tax Credits	30,545	33,691
WV Rate Stabilization Deferral	-	75,601
Over Recovery of Fuel Cost	68,704	-
Other Regulatory Liabilities	17,326	72
Long-term Risk Management Liabilities	54,327	44,517
Obligations Under Capital Leases	16,134	23,991
Asset Retirement Obligation	21,776	-
Deferred Credits and Other	<u>115,593</u>	<u>248,439</u>
TOTAL	<u>1,220,257</u>	<u>1,128,112</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$4,977,011</u>	<u>\$4,722,442</u>

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$280,040	\$205,492	\$161,818
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Cumulative Effect of Accounting Changes	(77,257)	-	-
Depreciation and Amortization	175,772	189,335	180,505
Deferred Income Taxes	24,563	16,777	42,498
Deferred Investment Tax Credits	(3,146)	(4,637)	(4,765)
Deferred Power Supply Costs, Net	74,071	6,365	1,411
Mark to Market of Risk Management Contracts	56,409	(21,151)	(68,254)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(6,825)	(83,453)	169,691
Fuel, Materials and Supplies	(1,252)	3,016	(19,957)
Accounts Payable	(17,611)	27,805	(45,073)
Taxes Accrued	21,078	(26,402)	(7,675)
Incentive Plan Accrued	(7,210)	(858)	(2,451)
Rate Stabilization Deferral	(75,601)	-	-
Change in Operating Reserves	(46,984)	(3,190)	(5,358)
Change in Other Assets	(17,813)	(43,338)	19,418
Change in Other Liabilities	<u>83,042</u>	<u>14,948</u>	<u>(27,954)</u>
Net Cash Flows From Operating Activities	<u>461,276</u>	<u>280,709</u>	<u>393,854</u>
INVESTING ACTIVITIES			
Construction Expenditures	(288,577)	(276,549)	(306,046)
Proceeds from Sale of Property and Other	<u>1,969</u>	<u>1,074</u>	<u>(7,252)</u>
Net Cash Flows Used For Investing Activities	<u>(286,608)</u>	<u>(275,475)</u>	<u>(313,298)</u>
FINANCING ACTIVITIES			
Issuance of Long-term Debt	580,649	647,401	124,588
Retirement of Long-term Debt	(622,737)	(315,007)	(175,000)
Retirement of Preferred Stock	(5,506)	-	-
Change in Short-term Debt (net)	-	-	(191,495)
Change in Advances from Affiliates, Net	43,789	(252,612)	300,204
Dividends Paid on Common Stock	(128,266)	(92,952)	(129,594)
Dividends Paid on Cumulative Preferred Stock	<u>(1,001)</u>	<u>(1,442)</u>	<u>(1,443)</u>
Net Cash Flows Used For Financing Activities	<u>(133,072)</u>	<u>(14,612)</u>	<u>(72,740)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	41,596	(9,378)	7,816
Cash and Cash Equivalents at Beginning of Period	<u>4,285</u>	<u>13,663</u>	<u>5,847</u>
Cash and Cash Equivalents at End of Period	<u>\$45,881</u>	<u>\$4,285</u>	<u>\$13,663</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$108,045,000, \$111,528,000 and \$117,283,000 and for income taxes was \$62,673,000, \$125,120,000 and \$56,981,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

					<u>2003</u>	<u>2002</u>
					(in thousands)	
COMMON SHAREHOLDER'S EQUITY					<u>\$1,336,987</u>	<u>\$1,166,057</u>
PREFERRED STOCK:						
No Par Value - Authorized 8,000,000 shares						
<u>Series</u>	<u>Call Price</u> <u>December 31,</u> <u>2003 (a)</u>	<u>Number of Shares Redeemed</u> <u>Year Ended December 31,</u>			<u>Shares</u> <u>Outstanding</u> <u>December 31, 2003</u>	
		<u>2003</u>	<u>2002</u>	<u>2001</u>		
Not Subject to Mandatory Redemption - \$100 Par:						
4-1/2%	\$110	60	6	-	177,839	<u>17,784</u> <u>17,790</u>
Subject to Mandatory Redemption - \$100 Par(b):						
5.90% (c)		25,000	-	-	22,100	2,210 4,710
5.92% (c)		30,000	-	-	31,500	<u>3,150</u> <u>6,150</u>
Total					<u>5,360</u>	<u>10,860</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):						
First Mortgage Bonds					340,269	489,697
Installment Purchase Contracts					276,477	235,027
Senior Unsecured Notes					1,244,813	1,166,609
Other Long-term Debt					2,522	2,528
Less Portion Due Within One Year					<u>(161,008)</u>	<u>(155,007)</u>
Long-term Debt Excluding Portion Due Within One Year					<u>1,703,073</u>	<u>1,738,854</u>
TOTAL CAPITALIZATION					<u>\$3,063,204</u>	<u>\$2,933,561</u>

- (a) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is \$100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed \$300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.
- (b) The sinking fund provisions of each series subject to mandatory redemption have been met by shares purchased in advance of the due date.
- (c) Commencing in 2003 and continuing through 2007 APCo may redeem at \$100 per share 25,000 shares of the 5.90% series and 30,000 shares of the 5.92% series outstanding under sinking fund provisions at its option and all outstanding shares must be redeemed in 2008. Shares previously redeemed may be applied to meet the sinking fund requirement.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6.00	2003 – November 1	\$-	\$30,000
7.70	2004 – September 1	21,000	21,000
7.85	2004 – November 1	50,000	50,000
8.00	2005 – May 1	50,000	50,000
6.89	2005 – June 22	30,000	30,000
6.80	2006 – March 1	100,000	100,000
8.50	2022 – December 1	-	70,000
7.80	2023 – May 1	-	30,237
7.15	2023 – November 1	-	20,000
7.125	2024 – May 1	45,000	45,000
8.00	2025 – June 1	45,000	45,000
	Unamortized Discount	(731)	(1,540)
Total		<u>\$340,269</u>	<u>\$489,697</u>

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds, by governmental authorities as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
Industrial Development Authority of Russell County, Virginia:			
7.70	2007 – November 1	\$-	\$17,500
(a)	2007 – November 1	17,500	-
5.00	2021 – November 1	19,500	19,500
Putnam County, West Virginia:			
(b)	2019 – June 1	40,000	-
6.60	2019 – July 1	-	30,000
5.45	2019 – June 1	40,000	40,000
(c)	2019 – May 1	30,000	-
Mason County, West Virginia:			
7-7/8	2013 – November 1	-	10,000
6.85	2022 – June 1	-	40,000
6.60	2022 – October 1	-	50,000
6.05	2024 – December 1	30,000	30,000
5.50	2022 – October 1	100,000	-
	Unamortized Discount	(523)	(1,973)
Total		<u>\$276,477</u>	<u>\$235,027</u>

- (a) Rate is an annual long-term fixed rate of 2.70% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by APCo (fixed rate bonds).
- (b) In December 2003 an auction rate was established. Auction rates are determined by standard procedures every 35 days. The rate on December 31, 2003 was 1.10%. The proceeds from the issuance were used to redeem the 5.45% Putnam County Installment Purchase Contracts on January 12, 2004.
- (c) Rate is an annual long-term fixed rate of 2.80% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by APCo (fixed rate bonds).

Under the terms of the installment purchase contracts, APCo 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.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
(a)	2003 – August 20	\$-	\$125,000
7.45	2004 – November 1	50,000	50,000
4.80	2005 – June 15	450,000	450,000
4.32	2007 – November 12	200,000	200,000
3.60	2008 – May 15	200,000	-
6.60	2009 – May 1	150,000	150,000
5.95	2033 – May 15	200,000	-
7.20	2038 – March 31	-	100,000
7.30	2038 – June 30	-	100,000
	Unamortized Discount	(5,187)	(8,391)
Total		<u>\$1,244,813</u>	<u>\$1,166,609</u>

- (a) A floating interest rate was determined monthly. The rate on December 31, 2002 was 2.167%.

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$161,008
2005	530,010
2006	147,511
2007	200,013
2008	200,014
Later Years	<u>631,966</u>
Total Principal Amount	1,870,522
Unamortized Discount	<u>(6,441)</u>
Total	<u>\$1,864,081</u>

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to APCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to APCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Appalachian Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Appalachian Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 Appalachian Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

**COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES**

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,431,851	\$1,400,160	\$1,350,319	\$1,304,409	\$1,190,997
Operating Expenses	<u>1,206,365</u>	<u>1,180,381</u>	<u>1,098,142</u>	<u>1,108,532</u>	<u>968,207</u>
Operating Income	225,486	219,779	252,177	195,877	222,790
Nonoperating Items, Net	(1,391)	15,263	7,738	5,153	2,709
Interest Charges	<u>50,948</u>	<u>53,869</u>	<u>68,015</u>	<u>80,828</u>	<u>75,229</u>
Income Before Extraordinary Item and Cumulative Effect	173,147	181,173	191,900	120,202	150,270
Extraordinary Loss (Net of Tax)	-	-	(30,024)	(25,236)	-
Cumulative Effect of Accounting Changes (Net of Tax)	<u>27,283</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	200,430	181,173	161,876	94,966	150,270
Preferred Stock Dividend Requirements (including Capital Stock Expense)	<u>1,016</u>	<u>1,365</u>	<u>1,890</u>	<u>1,783</u>	<u>2,131</u>
Earnings Applicable to Common Stock	<u><u>\$199,414</u></u>	<u><u>\$179,808</u></u>	<u><u>\$159,986</u></u>	<u><u>\$93,183</u></u>	<u><u>\$148,139</u></u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$3,570,443	\$3,467,626	\$3,354,320	\$3,266,794	\$3,151,619
Accumulated Depreciation	<u>1,389,586</u>	<u>1,369,153</u>	<u>1,283,712</u>	<u>1,211,728</u>	<u>1,129,007</u>
Net Electric Utility Plant	<u><u>\$2,180,857</u></u>	<u><u>\$2,098,473</u></u>	<u><u>\$2,070,608</u></u>	<u><u>\$2,055,066</u></u>	<u><u>\$2,022,612</u></u>
TOTAL ASSETS	<u><u>\$2,838,366</u></u>	<u><u>\$2,849,261</u></u>	<u><u>\$2,815,708</u></u>	<u><u>\$3,965,460</u></u>	<u><u>\$2,890,610</u></u>
Common Stock and Paid-in Capital	\$617,426	\$616,410	\$615,395	\$614,380	\$613,899
Retained Earnings	326,782	290,611	176,103	99,069	246,584
Accumulated Other Comprehensive Income (Loss)	<u>(46,327)</u>	<u>(59,357)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u><u>\$897,881</u></u>	<u><u>\$847,664</u></u>	<u><u>\$791,498</u></u>	<u><u>\$713,449</u></u>	<u><u>\$860,483</u></u>
Cumulative Preferred Stock - Subject to Mandatory Redemption (a)	<u><u>\$-</u></u>	<u><u>\$-</u></u>	<u><u>\$10,000</u></u>	<u><u>\$15,000</u></u>	<u><u>\$25,000</u></u>
Long-term Debt (a)	<u><u>\$897,564</u></u>	<u><u>\$621,626</u></u>	<u><u>\$791,848</u></u>	<u><u>\$899,615</u></u>	<u><u>\$924,545</u></u>
Obligations Under Capital Leases (a)	<u><u>\$15,618</u></u>	<u><u>\$27,610</u></u>	<u><u>\$34,887</u></u>	<u><u>\$42,932</u></u>	<u><u>\$40,270</u></u>
TOTAL CAPITALIZATION AND LIABILITIES	<u><u>\$2,838,366</u></u>	<u><u>\$2,849,261</u></u>	<u><u>\$2,815,708</u></u>	<u><u>\$3,965,460</u></u>	<u><u>\$2,890,610</u></u>

(a) Including portion due within one year.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

CSPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 698,000 retail customers in central and southern Ohio. 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 their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

The increase in Net Income of \$19 million in 2003 compared to 2002 was primarily due to a \$32 million increase in operating revenues, a \$37 million decrease in income taxes (includes Operating Income Taxes and Nonoperating Income Tax Expense) and a \$27 million net-of-tax Cumulative Effect of Accounting Changes, which were partially offset by a \$48 million increase in fuel and purchased power expenses and a \$34 million decrease in results from risk management activities.

Operating Income

Operating Income increased \$6 million primarily due to:

- An increase of \$27 million in Sales to AEP Affiliates and an increase of \$34 million of wholesale sales to non-affiliates due primarily to an increase in sales of MWH.
- A decrease in Other Operation expense of \$19 million primarily due to decreases in factored receivables expenses, AEP transmission equalization expenses and personal injuries and property damage expenses. Administrative and general salaries also decreased due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits recorded in 2002.
- Income Taxes decreased by \$20 million primarily due to state income tax return and accrual adjustments.

The increase in Operating Income was partially offset by:

- A decrease of \$34 million in retail revenues resulting from milder spring and summer weather and a sluggish economy. A decrease of 42% in cooling degree days from the prior year was partially offset by a 7% increase in heating degree days.
- An increase of \$18 million in fuel expense due to a 3% increase in coal costs and a 6% increase in MWH of power generation.
- An increase of \$27 million in Purchased Electricity from AEP Affiliates to support wholesale sales to non-affiliated entities.
- An increase of \$15 million in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages and increased maintenance of overhead lines resulting from severe storm damage.

Other Impacts on Earnings

Nonoperating Income decreased \$36 million primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area.

Nonoperating Income Tax Credit increased due to a decrease in pre-tax nonoperating book income and changes related to consolidated tax savings.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	A3	BBB	A-

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$11,000	\$36,000	\$112,000	\$738,564	\$897,564
Advances from Affiliates	6,517	-	-	-	6,517
Capital Lease Obligations	4,959	6,701	3,823	2,096	17,579
Unconditional Purchase Obligations (a)	81,500	9,854	-	-	91,354
Noncancellable Operating Leases	<u>5,078</u>	<u>7,438</u>	<u>3,814</u>	<u>2,726</u>	<u>19,056</u>
Total	<u>\$109,054</u>	<u>\$59,993</u>	<u>\$119,637</u>	<u>\$743,386</u>	<u>\$1,032,070</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$65,117
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(23,010)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	81
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(3,135)
Changes in Fair Value of Risk Management Contracts (e)	(716)
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	<u>38,337</u>
Net Cash Flow Hedge Contracts (g)	311
DETM Assignment (h)	<u>(18,185)</u>
Ending Balance December 31, 2003	<u><u>\$20,463</u></u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
- (h)See Note 17 “Related Party Transactions.”

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After</u> <u>2008</u>	<u>Total (c)</u>
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	\$687	\$(138)	\$16	\$108	\$-	\$-	\$673
Prices Provided by Other External Sources – OTC Broker Quotes (a)	13,378	4,795	4,703	1,911	959	-	25,746
Prices Based on Models and Other Valuation Methods (b)	<u>(3)</u>	<u>20</u>	<u>1,866</u>	<u>2,157</u>	<u>1,984</u>	<u>5,894</u>	<u>11,918</u>
Total	<u>\$14,062</u>	<u>\$4,677</u>	<u>\$6,585</u>	<u>\$4,176</u>	<u>\$2,943</u>	<u>\$5,894</u>	<u>\$38,337</u>

- (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” if there is 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$(267)
Changes in Fair Value (a)	194
Reclassifications from AOCI to Net Income (b)	<u>275</u>
Ending Balance December 31, 2003	<u>\$ 202</u>

- (a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
- (b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$940 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Energy and Gas Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$336	\$1,303	\$546	\$130	\$867	\$2,654	\$949	\$192

VaR Associated with Debt Outstanding

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 \$98 million and \$33 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
<u>OPERATING REVENUES</u>			
Electric Generation, Transmission and Distribution	\$1,347,482	\$1,342,958	\$1,282,808
Sales to AEP Affiliates	<u>84,369</u>	<u>57,202</u>	<u>67,511</u>
TOTAL	<u>1,431,851</u>	<u>1,400,160</u>	<u>1,350,319</u>
<u>OPERATING EXPENSES</u>			
Fuel for Electric Generation	203,399	185,086	175,153
Purchased Electricity for Resale	17,730	15,023	10,957
Purchased Electricity from AEP Affiliates	337,323	310,605	292,199
Other Operation	218,466	237,802	219,497
Maintenance	75,319	60,003	62,454
Depreciation and Amortization	135,964	131,624	127,364
Taxes Other Than Income Taxes	133,754	136,024	111,481
Income Taxes	<u>84,410</u>	<u>104,214</u>	<u>99,037</u>
TOTAL	<u>1,206,365</u>	<u>1,180,381</u>	<u>1,098,142</u>
OPERATING INCOME	225,486	219,779	252,177
Nonoperating Income (Loss)	(7,489)	28,280	34,656
Nonoperating Expenses	4,650	6,228	22,995
Nonoperating Income Tax Expense (Credit)	(10,748)	6,789	3,923
Interest Charges	<u>50,948</u>	<u>53,869</u>	<u>68,015</u>
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	173,147	181,173	191,900
Extraordinary Loss – Discontinuance of Regulatory Accounting for Generation – Net of Tax (Note 2)	-	-	(30,024)
Cumulative Effect of Accounting Changes (Net of Tax)	<u>27,283</u>	<u>-</u>	<u>-</u>
NET INCOME	200,430	181,173	161,876
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	<u>1,016</u>	<u>1,365</u>	<u>1,890</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$199,414</u>	<u>\$179,808</u>	<u>\$159,986</u>

The common stock of CSPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on Page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$41,026	\$573,354	\$99,069	\$-	\$713,449
Common Stock Dividends Declared			(82,952)		(82,952)
Preferred Stock Dividends Declared			(875)		(875)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					<u>629,622</u>
COMPREHENSIVE INCOME					
NET INCOME			161,876		<u>161,876</u>
TOTAL COMPREHENSIVE INCOME					<u>161,876</u>
DECEMBER 31, 2001	\$41,026	\$574,369	\$176,103	\$-	\$791,498
Common Stock Dividends Declared			(65,300)		(65,300)
Preferred Stock Dividends Declared			(350)		(350)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					<u>725,848</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Power Hedges				(267)	(267)
Minimum Pension Liability				(59,090)	(59,090)
NET INCOME			181,173		<u>181,173</u>
TOTAL COMPREHENSIVE INCOME					<u>121,816</u>
DECEMBER 31, 2002	\$41,026	\$575,384	\$290,611	\$(59,357)	\$847,664
Common Stock Dividends Declared			(163,243)		(163,243)
Capital Stock Expense		1,016	(1,016)		-
TOTAL					<u>684,421</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				469	469
Minimum Pension Liability				12,561	12,561
NET INCOME			200,430		<u>200,430</u>
TOTAL COMPREHENSIVE INCOME					<u>213,460</u>
DECEMBER 31, 2003	<u>\$41,026</u>	<u>\$576,400</u>	<u>\$326,782</u>	<u>\$(46,327)</u>	<u>\$897,881</u>

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$1,610,888	\$1,582,627
Transmission	425,512	413,286
Distribution	1,253,760	1,208,255
General	166,002	165,025
Construction Work in Progress	114,281	98,433
TOTAL	<u>3,570,443</u>	<u>3,467,626</u>
Accumulated Depreciation and Amortization	<u>1,389,586</u>	<u>1,369,153</u>
TOTAL - NET	<u>2,180,857</u>	<u>2,098,473</u>
 <u>OTHER PROPERTY AND INVESTMENTS</u>		
Non-Utility Property, Net	22,417	23,680
Other Investments	<u>8,663</u>	<u>12,079</u>
TOTAL	<u>31,080</u>	<u>35,759</u>
 <u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	4,142	1,479
Advances to Affiliates, Net	-	31,257
Accounts Receivable:		
Customers	47,099	70,704
Affiliated Companies	68,168	54,518
Accrued Unbilled Revenues	23,723	12,671
Miscellaneous	5,257	867
Allowance for Uncollectible Accounts	(531)	(634)
Fuel	14,365	24,844
Materials and Supplies	44,377	40,339
Risk Management Assets	40,095	63,197
Margin Deposits	6,636	824
Prepayments and Other	<u>12,444</u>	<u>6,635</u>
TOTAL	<u>265,775</u>	<u>306,701</u>
 <u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
SFAS 109 Regulatory Assets, Net	16,027	26,290
Transition Regulatory Assets	188,532	204,961
Unamortized Loss on Reacquired Debt	13,659	5,978
Other	24,966	20,453
Long-term Risk Management Assets	39,932	77,810
Deferred Property Taxes	62,262	61,733
Deferred Charges	<u>15,276</u>	<u>11,103</u>
TOTAL	<u>360,654</u>	<u>408,328</u>
 TOTAL ASSETS	<u>\$2,838,366</u>	<u>\$2,849,261</u>

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>CAPITALIZATION</u>		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	\$41,026	\$41,026
Paid-in Capital	576,400	575,384
Retained Earnings	326,782	290,611
Accumulated Other Comprehensive Income (Loss)	(46,327)	(59,357)
Total Common Shareholder's Equity	<u>897,881</u>	<u>847,664</u>
Long-term Debt:		
Nonaffiliated	886,564	418,626
Affiliated	-	160,000
Total Long-term Debt	<u>886,564</u>	<u>578,626</u>
TOTAL	<u>1,784,445</u>	<u>1,426,290</u>
<u>CURRENT LIABILITIES</u>		
Short-term Debt – Affiliates	-	290,000
Long-term Debt Due Within One Year - Nonaffiliated	11,000	43,000
Advances from Affiliates, Net	6,517	-
Accounts Payable:		
General	58,220	89,736
Affiliated Companies	53,572	81,599
Customer Deposits	19,727	14,719
Taxes Accrued	132,853	112,172
Interest Accrued	16,528	9,798
Risk Management Liabilities	28,966	46,375
Obligations Under Capital Leases	4,221	5,967
Other	25,364	16,104
TOTAL	<u>356,968</u>	<u>709,470</u>
<u>DEFERRED CREDITS AND OTHER LIABILITIES</u>		
Deferred Income Taxes	458,498	437,771
Regulatory Liabilities:		
Asset Removal Costs	99,119	-
Deferred Investment Tax Credits	30,797	33,907
Long-term Risk Management Liabilities	30,598	29,926
Obligations Under Capital Leases	11,397	21,643
Asset Retirement Obligations	8,740	-
Deferred Credits and Other	57,804	190,254
TOTAL	<u>696,953</u>	<u>713,501</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$2,838,366</u>	<u>\$2,849,261</u>

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$200,430	\$181,173	\$161,876
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Cumulative Effect of Accounting Changes	(27,283)	-	-
Depreciation and Amortization	135,964	131,753	128,500
Deferred Income Taxes	(4,514)	23,292	24,108
Deferred Investment Tax Credits	(3,110)	(3,269)	(4,058)
Mark-to-Market of Risk Management Contracts	41,830	(16,667)	(44,680)
Extraordinary Loss	-	-	30,024
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(5,590)	(9,576)	22,538
Fuel, Materials and Supplies	6,441	(6,180)	(7,780)
Accounts Payable	(59,543)	26,949	(16,249)
Taxes Accrued	20,681	(4,192)	(46,540)
Interest Accrued	6,730	(1,108)	(2,462)
Deferred Property Tax	(529)	(13,732)	22,920
Change in Other Assets	(20,563)	5,705	(14)
Change in Other Liabilities	(8,762)	(17,148)	(34,739)
Net Cash Flows From Operating Activities	<u>282,182</u>	<u>297,000</u>	<u>233,444</u>
INVESTING ACTIVITIES			
Construction Expenditures	(136,291)	(136,800)	(132,532)
Proceeds from Sale of Property	1,644	730	10,841
Net Cash Flows Used For Investing Activities	<u>(134,647)</u>	<u>(136,070)</u>	<u>(121,691)</u>
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Affiliated	-	160,000	200,000
Issuance of Long-term Debt – Nonaffiliated	643,097	-	-
Change in Advances to/from Affiliates, Net	37,774	(212,641)	92,652
Retirement of Long-term Debt – Nonaffiliated	(212,500)	(133,343)	(314,733)
Retirement of Long-term Debt – Affiliated	(160,000)	(200,000)	-
Retirement of Cumulative Preferred Stock	-	(10,000)	(5,000)
Change in Short-term Debt – Affiliates	(290,000)	290,000	-
Dividends Paid on Common Stock	(163,243)	(65,300)	(82,952)
Dividends Paid on Cumulative Preferred Stock	-	(525)	(962)
Net Cash Flows Used For Financing Activities	<u>(144,872)</u>	<u>(171,809)</u>	<u>(110,995)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	2,663	(10,879)	758
Cash and Cash Equivalents at Beginning of Period	<u>1,479</u>	<u>12,358</u>	<u>11,600</u>
Cash and Cash Equivalents at End of Period	<u>\$4,142</u>	<u>\$1,479</u>	<u>\$12,358</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$42,601,000, \$53,514,000 and \$68,596,000 and for income taxes was \$63,907,000, \$117,591,000 and \$80,485,000 in 2003, 2002 and 2001, respectively. Non-cash acquisitions under capital leases was \$1,019,000 in 2001. There were no non-cash capital lease acquisitions in 2003 or 2002.

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
COMMON SHAREHOLDER'S EQUITY	<u>\$897,881</u>	<u>\$847,664</u>
PREFERRED STOCK (a)		
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	10,944	222,797
Installment Purchase Contracts	91,329	91,275
Senior Unsecured Notes	795,291	147,554
Notes – Affiliated	-	160,000
Less Portion Due Within One Year	<u>(11,000)</u>	<u>(43,000)</u>
Total Long-term Debt Excluding Portion Due Within One Year	<u>886,564</u>	<u>578,626</u>
TOTAL CAPITALIZATION	<u>\$1,784,445</u>	<u>\$1,426,290</u>

(a) At December 31, 2003 and 2002 there were no shares outstanding, 2,500,000 authorized shares at \$100 par value and 7,000,000 authorized shares at \$25 par value.

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		(in thousands)	
6.80	2003 – May 1	\$-	\$13,000
6.60	2003 – August 1	-	25,000
6.10	2003 – November 1	-	5,000
6.55	2004 – March 1	-	26,500
6.75	2004 – May 1	-	26,000
8.70	2022 – July 1	-	2,000
8.55	2022 – August 1	-	15,000
8.40	2022 – August 15	-	14,000
8.40	2022 – October 15	-	13,000
7.90	2023 – May 1	-	40,000
7.75	2023 – August 1	-	33,000
7.60	2024 – May 1 (a)	11,000	11,000
	Unamortized Discount	<u>(56)</u>	<u>(703)</u>
Total		<u>\$10,944</u>	<u>\$222,797</u>

(a) This bond will be redeemed in May 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien 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.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		(in thousands)	
6.375	2020 - December 1	\$48,550	\$48,550
6.25	2020 - December 1	43,695	43,695
	Unamortized Discount	<u>(916)</u>	<u>(970)</u>
Total		<u>\$91,329</u>	<u>\$91,275</u>

Under the terms of the Installment Purchase Contracts, CSPCo 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 the Zimmer Plant. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		(in thousands)	
6.85	2005 – October 3	\$36,000	\$36,000
6.51	2008 – February 1	52,000	52,000
6.55	2008 – June 26	60,000	60,000
4.40	2010 – December 1	150,000	-
5.50	2013 – March 1	250,000	-
6.60	2033 – March 1	250,000	-
	Unamortized Discount	<u>(2,709)</u>	<u>(446)</u>
Total		<u>\$795,291</u>	<u>\$147,554</u>

Notes Payable to parent company were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6.501%	2006 – May 15	<u>\$ -</u>	<u>\$160,000</u>

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$11,000
2005	36,000
2006	-
2007	-
2008	112,000
Later Years	<u>742,245</u>
Total Principal Amount	901,245
Unamortized Discount	<u>(3,681)</u>
Total	<u>\$897,564</u>

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to CSPCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to CSPCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Columbus Southern Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 Columbus Southern Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

**INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES**

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,595,596	\$1,526,764	\$1,526,997	\$1,488,209	\$1,351,666
Operating Expenses	<u>1,409,529</u>	<u>1,375,575</u>	<u>1,367,292</u>	<u>1,522,911</u>	<u>1,243,014</u>
Operating Income (Loss)	186,067	151,189	159,705	(34,702)	108,652
Nonoperating Items, Net	(13,465)	16,726	9,730	9,933	4,530
Interest Charges	<u>83,054</u>	<u>93,923</u>	<u>93,647</u>	<u>107,263</u>	<u>80,406</u>
Net Income (Loss) Before Cumulative Effect of Accounting Change	89,548	73,992	75,788	(132,032)	32,776
Cumulative Effect of Accounting Change (Net of Tax)	<u>(3,160)</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income (Loss)	86,388	73,992	75,788	(132,032)	32,776
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	<u>2,509</u>	<u>4,601</u>	<u>4,621</u>	<u>4,624</u>	<u>4,885</u>
Earnings (Loss) Applicable to Common Stock	<u>\$83,879</u>	<u>\$69,391</u>	<u>\$71,167</u>	<u>\$(136,656)</u>	<u>\$27,891</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$5,306,182	\$5,029,958	\$4,923,721	\$4,871,473	\$4,770,027
Accumulated Depreciation and Amortization	<u>2,490,912</u>	<u>2,318,063</u>	<u>2,198,524</u>	<u>2,057,542</u>	<u>1,981,430</u>
Net Electric Utility Plant	<u>\$2,815,270</u>	<u>\$2,711,895</u>	<u>\$2,725,197</u>	<u>\$2,813,931</u>	<u>\$2,788,597</u>
TOTAL ASSETS	<u>\$4,659,071</u>	<u>\$4,837,732</u>	<u>\$4,632,510</u>	<u>\$5,997,087</u>	<u>\$4,788,177</u>
Common Stock and Paid-in Capital	\$915,278	\$915,144	\$789,800	\$789,656	\$789,323
Retained Earnings	187,875	143,996	74,605	3,443	166,389
Accumulated Other Comprehensive Income (Loss)	<u>(25,106)</u>	<u>(40,487)</u>	<u>(3,835)</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u>\$1,078,047</u>	<u>\$1,018,653</u>	<u>\$860,570</u>	<u>\$793,099</u>	<u>\$955,712</u>
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	\$8,101	\$8,101	\$8,736	\$8,736	\$9,248
Subject to Mandatory Redemption (a)	<u>63,445</u>	<u>64,945</u>	<u>64,945</u>	<u>64,945</u>	<u>64,945</u>
Total Cumulative Preferred Stock	<u>\$71,546</u>	<u>\$73,046</u>	<u>\$73,681</u>	<u>\$73,681</u>	<u>\$74,193</u>
Long-term Debt (a)	<u>\$1,339,359</u>	<u>\$1,617,062</u>	<u>\$1,652,082</u>	<u>\$1,388,939</u>	<u>\$1,324,326</u>
Obligations Under Capital Leases (a)	<u>\$37,843</u>	<u>\$50,848</u>	<u>\$61,933</u>	<u>\$163,173</u>	<u>\$187,965</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$4,659,071</u>	<u>\$4,837,732</u>	<u>\$4,632,510</u>	<u>\$5,997,087</u>	<u>\$4,788,177</u>

(a) Including portion due within one year.

INDIANA MICHIGAN 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 575,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. 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.

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

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

During 2003, Net Income increased \$12 million including an unfavorable \$3 million Cumulative Effect of Accounting Change (see Note 2). During 2003, Net Income Before Cumulative Effect of Accounting Change increased \$15 million due to reduced financing costs and an improvement in Operating Income resulting from higher margins on wholesale sales and lower Other Operation expense.

During 2002, Net Income decreased by \$2 million due to increased operations and maintenance costs incurred as part of planned and unplanned outages at Cook and Rockport plants.

2003 Compared to 2002

Operating Income

Operating Income increased \$35 million primarily due to:

- Increased wholesale sales of \$69 million including system and power optimization sales, transmission revenues and risk management activities reflecting availability of AEP's generation and market conditions.
- Increased Sales to AEP Affiliates of \$35 million due to increased capacity revenue.
- Decreased Other Operations expense of \$45 million due primarily to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits of \$15 million recorded in 2002.

The increase in Operating Income was partially offset by:

- Decreased retail revenues of \$37 million due primarily to milder summer weather and economic pressures on industrial customers. Cooling degree days declined approximately 42% this year compared with last year. Industrial revenues dropped 3% from prior year.
- Increased Fuel for Electric Generation expense of \$11 million reflecting an increase in the average cost of fuel and increased coal-fired generation in 2003 as Rockport's availability increased.
- Increased Purchased Electricity from AEP Affiliates of \$41 million due to purchasing more power from the AEP Power Pool to support wholesale sales to unaffiliated entities.
- Increased Income Tax expense of \$12 million reflecting an increase in pre-tax operating income partially offset by temporary differences accounted for on a flow-through basis and tax return adjustments.

Other Impacts on Earnings

Nonoperating Income decreased \$30 million primarily due to lower margins for power sold outside of AEP's traditional market reflecting AEP's plan to exit those risk management activities.

Nonoperating Expenses increased \$16 million primarily due to a \$10 million write-down of western coal lands (see Note 10).

Nonoperating Income Taxes decreased \$16 million reflecting the decrease in pre-tax nonoperating income.

Interest Charges decreased \$11 million primarily due to a reduction in outstanding long-term debt of \$255 million which was retired in May 2003 using lower rate short-term debt.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to the implementation of the requirements of EITF 02-3 (see Note 2).

2002 Compared to 2001

Operating Income

Operating Income decreased \$9 million primarily due to:

- Decreased Sales to AEP Affiliates of \$41 million reflecting less energy to sell due to outages. In 2002, both units of Cook plant were shut down for refueling and both Rockport units were down for planned boiler maintenance.
- Increased Other Operation expense of \$14 million due to increased costs for pensions, insurance and other benefits.
- Increased Maintenance expense of \$24 million reflecting two nuclear refueling outages in 2002.

The decrease in Operating Income was partially offset by:

- Increased Retail revenues of \$35 million reflecting a 4% increase in sales.
- Decreased Fuel for Electric Generation expense of \$11 million reflecting a decline in the average cost of fuel and decreased nuclear generation.
- An \$8 million decrease in Taxes Other Than Income Taxes reflects a favorable tax law change in Indiana effective March 2002.
- Decreased Income Taxes of \$15 million reflecting a decrease in pre-tax operating income.

Other Impacts on Earnings

Nonoperating Expenses decreased \$10 million due to a decrease in trading overheads and traders' incentive compensation.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	Baa1	BBB	BBB+
Senior Unsecured Debt	Baa2	BBB	BBB

During the first quarter of 2003, Moody's Investors Service (Moody's), Standard & Poors (S&P) and Fitch Rating Service completed their reviews of AEP and its rated subsidiaries. The reviews resulted in downgrades of debt ratings. The completion of these reviews was a culmination of ratings action started during 2002.

Cash Flow

Cash flows for 2003, 2002 and 2001 were as follows:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
Cash and cash equivalents at beginning of period	<u>\$3,237</u>	<u>\$16,804</u>	<u>\$14,835</u>
Cash flow from (used for):			
Operating activities	222,773	228,234	236,207
Investing activities	(182,703)	(165,725)	(182,594)
Financing activities	<u>(39,393)</u>	<u>(76,076)</u>	<u>(51,644)</u>
Net increase (decrease) in cash and cash equivalents	<u>677</u>	<u>(13,567)</u>	<u>1,969</u>
Cash and cash equivalents at end of period	<u><u>\$3,914</u></u>	<u><u>\$3,237</u></u>	<u><u>\$16,804</u></u>

Operating Activities

Operating activities during 2003 provided \$5 million less cash than during 2002 which was \$8 million less than during 2001 largely due to working capital requirements and changes in mark-to-market of risk management contracts.

Investing Activities

Cash flows used for investing activities during 2003 were \$183 million compared to \$166 million during 2002. The primary reason for the year-over-year variance was increased construction expenditures of \$17 million. Construction expenditures increased \$76 million comparing 2002 with 2001. In 2001, we bought out nuclear fuel leases using \$93 million of operating cash. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability.

Financing Activities

Financing activities for 2003 used \$39 million of cash from operations primarily to pay common dividends. During 2003, we redeemed \$285 million of long-term debt using short-term debt and refinanced \$65 million of our installment purchase contracts at lower fixed rates until October 2006.

During 2002, we redeemed \$340 million of long-term debt and \$145 million of short-term debt using cash from operations, a \$125 million capital contribution from our parent company and proceeds from the issuance of \$300 million of long-term debt.

During 2001, we issued \$300 million of long-term debt to reduce short-term debt.

Financing Activity

Long-term debt issuances and retirements during 2003 were:

Issuances

<u>Type of Debt</u>	<u>Principal Amount</u> (in millions)	<u>Interest Rate</u> (%)	<u>Due Date</u>
Installment Purchase Contracts	\$25	2.625(a)	2019
Installment Purchase Contracts (a) Fixed Until October 1, 2006	40	2.625(a)	2025

Retirements

<u>Type of Debt</u>	<u>Principal Amount</u> (in millions)	<u>Interest Rate</u> (%)	<u>Due Date</u>
First Mortgage Bonds	\$30	6.10	2003
First Mortgage Bonds	75	8.50	2022
First Mortgage Bonds	15	7.35	2023
Junior Debentures	40	8.00	2026
Junior Debentures	125	7.60	2038
Installment Purchase Contracts	25	7.00	2015
Installment Purchase Contracts	40	7.60	2016

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:

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 \$1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

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. 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 the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$205	\$365	\$100	\$669	\$1,339
Advances from Affiliates	99	-	-	-	99
Preferred Stock Subject to Mandatory Redemption	-	-	16	47	63
Capital Lease Obligations	10	14	16	6	46
Unconditional Purchase Obligations (a)	107	89	82	161	439
Noncancellable Operating Leases	<u>104</u>	<u>191</u>	<u>182</u>	<u>1,097</u>	<u>1,574</u>
Total	<u>\$525</u>	<u>\$659</u>	<u>\$396</u>	<u>\$1,980</u>	<u>\$3,560</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under “Off-Balance Sheet Arrangements” above, have been employed for a contractual cash obligation reported in the above table. The lease of Rockport Unit 2 is reported in Noncancellable Operating Leases.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power	
Beginning Balance December 31, 2002	\$70,861
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(18,666)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	88
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,861)
Changes in Fair Value of Risk Management Contracts (e)	765
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	<u>(6,192)</u>
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	41,995
Net Cash Flow Hedge Contracts (g)	341
DETM Assignment (h)	<u>(19,932)</u>
Ending Balance December 31, 2003	<u><u>\$22,404</u></u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
- (h)See Note 17 “Related Party Transactions.”

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003**

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
			<u>(in thousands)</u>				
Prices Actively Quoted – Exchange Traded Contracts	\$753	\$(151)	\$18	\$118	\$-	\$-	\$738
Prices Provided by Other External Sources – OTC Broker Quotes (a)	14,786	5,256	5,154	2,095	1,051	-	28,342
Prices Based on Models and Other Valuation Methods (b)	<u>(151)</u>	<u>23</u>	<u>2,045</u>	<u>2,364</u>	<u>2,174</u>	<u>6,460</u>	<u>12,915</u>
Total	<u>\$15,388</u>	<u>\$5,128</u>	<u>\$7,217</u>	<u>\$4,577</u>	<u>\$3,225</u>	<u>\$6,460</u>	<u>\$41,995</u>

- (a) “Prices Provided by Other External Sources” 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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

**Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003**

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$ (286)
Changes in Fair Value (a)	209
Reclassifications from AOCI to Net Income (b)	<u>299</u>
Ending Balance December 31, 2003	<u>\$ 222</u>

- (a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.
- (b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$1,031 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

<u>December 31, 2003</u>				<u>December 31, 2002</u>			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$368	\$1,429	\$598	\$142	\$927	\$2,840	\$1,016	\$206

VaR Associated with Debt Outstanding

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 \$79 million and \$85 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,346,393	\$1,312,626	\$1,271,958
Sales to AEP Affiliates	<u>249,203</u>	<u>214,138</u>	<u>255,039</u>
TOTAL	<u>1,595,596</u>	<u>1,526,764</u>	<u>1,526,997</u>
OPERATING EXPENSES			
Fuel for Electric Generation	250,890	239,455	250,098
Purchased Electricity for Resale	28,327	23,443	18,707
Purchased Electricity from AEP Affiliates	274,400	233,724	238,237
Other Operation	417,636	462,707	449,115
Maintenance	158,281	151,602	127,263
Depreciation and Amortization	171,281	168,070	164,230
Taxes Other Than Income Taxes	57,788	57,721	65,518
Income Taxes	<u>50,926</u>	<u>38,853</u>	<u>54,124</u>
TOTAL	<u>1,409,529</u>	<u>1,375,575</u>	<u>1,367,292</u>
OPERATING INCOME	186,067	151,189	159,705
Nonoperating Income	53,928	84,084	85,673
Nonoperating Expenses	77,171	61,374	70,900
Nonoperating Income Tax Expense (Credit)	(9,778)	5,984	5,043
Interest Charges	<u>83,054</u>	<u>93,923</u>	<u>93,647</u>
Net Income Before Cumulative Effect of Accounting Change	89,548	73,992	75,788
Cumulative Effect of Accounting Change (Net of Tax)	<u>(3,160)</u>	<u>-</u>	<u>-</u>
NET INCOME	86,388	73,992	75,788
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	<u>2,509</u>	<u>4,601</u>	<u>4,621</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$83,879</u>	<u>\$69,391</u>	<u>\$71,167</u>

The common stock of I&M is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$56,584	\$733,072	\$3,443	\$-	\$793,099
Preferred Stock Dividends			(4,487)		(4,487)
Capital Stock Expense		144	(139)		<u>5</u>
					<u>788,617</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				(3,835)	(3,835)
NET INCOME			75,788		<u>75,788</u>
TOTAL COMPREHENSIVE INCOME					<u>71,953</u>
DECEMBER 31, 2001	\$56,584	\$733,216	\$74,605	\$(3,835)	\$860,570
Capital Contributions from Parent Company		125,000			125,000
Preferred Stock Dividends			(4,467)		(4,467)
Capital Stock Expense		344	(134)		<u>210</u>
					<u>981,313</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				3,835	3,835
Unrealized Loss on Cash Flow Power Hedges				(286)	(286)
Minimum Pension Liability				(40,201)	(40,201)
NET INCOME			73,992		<u>73,992</u>
TOTAL COMPREHENSIVE INCOME					<u>37,340</u>
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)		<u>-</u>
					<u>976,278</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				508	508
Minimum Pension Liability				14,873	14,873
NET INCOME			86,388		<u>86,388</u>
TOTAL COMPREHENSIVE INCOME					<u>101,769</u>
DECEMBER 31, 2003	<u>\$56,584</u>	<u>\$858,694</u>	<u>\$187,875</u>	<u>\$(25,106)</u>	<u>\$1,078,047</u>

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$2,878,051	\$2,768,463
Transmission	1,000,926	971,599
Distribution	958,966	921,835
General (including nuclear fuel)	274,283	220,137
Construction Work in Progress	193,956	147,924
TOTAL	<u>5,306,182</u>	<u>5,029,958</u>
Accumulated Depreciation and Amortization	<u>2,490,912</u>	<u>2,318,063</u>
TOTAL - NET	<u>2,815,270</u>	<u>2,711,895</u>
<u>OTHER PROPERTY AND INVESTMENTS</u>		
Nuclear Decommissioning and Spent Nuclear Fuel		
Disposal Trust Funds	982,394	870,754
Non-Utility Property, Net	52,303	69,252
Other Investments	43,797	51,689
TOTAL	<u>1,078,494</u>	<u>991,695</u>
<u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	3,914	3,237
Advances to Affiliates	-	191,226
Accounts Receivable:		
Customers	61,084	92,929
Affiliated Companies	124,826	122,489
Accrued Unbilled Revenues	2,000	6,511
Miscellaneous	4,498	4,872
Allowance for Uncollectible Accounts	(531)	(578)
Fuel	33,968	32,731
Materials and Supplies	105,328	95,552
Risk Management Assets	44,071	67,985
Margin Deposits	7,245	890
Prepayments and Other	10,673	11,172
TOTAL	<u>397,076</u>	<u>629,016</u>
<u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	151,973	163,928
Deferred Fuel Costs	-	37,501
Cook Plant Restart Costs	-	40,000
Incremental Nuclear Refueling Outage Expenses, Net	57,326	29,572
Other	66,978	77,211
Long-term Risk Management Assets	43,768	83,265
Deferred Property Taxes	21,916	22,271
Deferred Charges and Other Assets	26,270	51,378
TOTAL	<u>368,231</u>	<u>505,126</u>
TOTAL ASSETS	<u>\$4,659,071</u>	<u>\$4,837,732</u>

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
CAPITALIZATION		
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	858,694	858,560
Retained Earnings	187,875	143,996
Accumulated Other Comprehensive Income (Loss)	(25,106)	(40,487)
Total Common Shareholder's Equity	<u>1,078,047</u>	<u>1,018,653</u>
Cumulative Preferred Stock – Not Subject to Mandatory Redemption	<u>8,101</u>	<u>8,101</u>
Total Shareholder's Equity	<u>1,086,148</u>	<u>1,026,754</u>
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	63,445	64,945
Long-term Debt	<u>1,134,359</u>	<u>1,587,062</u>
TOTAL	<u>2,283,952</u>	<u>2,678,761</u>
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	205,000	30,000
Advances from Affiliates	98,822	-
Accounts Payable:		
General	101,776	125,048
Affiliated Companies	47,484	93,608
Customer Deposits	21,955	16,660
Taxes Accrued	42,189	71,559
Interest Accrued	17,963	21,481
Risk Management Liabilities	31,898	48,568
Obligations Under Capital Leases	6,528	8,229
Other	<u>57,675</u>	<u>76,162</u>
TOTAL	<u>631,290</u>	<u>491,315</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	337,376	356,197
Regulatory Liabilities:		
Asset Removal Costs	263,015	-
Deferred Investment Tax Credits	90,278	97,709
Excess ARO for Nuclear Decommissioning	215,715	-
Other	61,268	65,983
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	70,179	73,885
Long-term Risk Management Liabilities	33,537	32,261
Obligations Under Capital Leases	31,315	42,619
Asset Retirement Obligations	553,219	-
Nuclear Decommissioning	-	620,672
Deferred Credits and Other	<u>87,927</u>	<u>378,330</u>
TOTAL	<u>1,743,829</u>	<u>1,667,656</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$4,659,071</u>	<u>\$4,837,732</u>

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$86,388	\$73,992	\$75,788
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Impairments	10,300	-	-
Cumulative Effect of Accounting Change	3,160	-	-
Depreciation and Amortization	171,281	168,070	166,360
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(27,754)	(26,577)	418
Unrecovered Fuel and Purchased Power Costs	37,501	37,501	37,501
Amortization of Nuclear Outage Costs	40,000	40,000	40,000
Deferred Income Taxes	(14,894)	(16,921)	(29,205)
Deferred Investment Tax Credits	(7,431)	(7,740)	(8,324)
Mark-to-Market of Risk Management Contracts	43,938	(9,517)	(62,647)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	34,346	(106,683)	62,769
Fuel, Materials and Supplies	(11,013)	(7,854)	(19,426)
Accounts Payable	(69,396)	87,934	(60,185)
Taxes Accrued	(29,370)	1,798	1,345
Change in Other Assets	(24,302)	(29,264)	2,622
Change in Other Liabilities	(19,981)	23,495	29,191
Net Cash Flows From Operating Activities	<u>222,773</u>	<u>228,234</u>	<u>236,207</u>
INVESTING ACTIVITIES			
Construction Expenditures	(184,188)	(167,484)	(91,052)
Buyout of Nuclear Fuel Leases	-	-	(92,616)
Other	1,485	1,759	1,074
Net Cash Flows Used For Investing Activities	<u>(182,703)</u>	<u>(165,725)</u>	<u>(182,594)</u>
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	125,000	-
Issuance of Long-term Debt	64,434	288,732	297,656
Retirement of Cumulative Preferred Stock	(1,500)	(424)	-
Retirement of Long-term Debt	(350,000)	(340,000)	(44,922)
Change in Advances to/from Affiliates, Net	290,048	(144,917)	(299,891)
Dividends Paid on Common Stock	(40,000)	-	-
Dividends Paid on Cumulative Preferred Stock	(2,375)	(4,467)	(4,487)
Net Cash Flows Used For Financing Activities	<u>(39,393)</u>	<u>(76,076)</u>	<u>(51,644)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	677	(13,567)	1,969
Cash and Cash Equivalents at Beginning of Period	<u>3,237</u>	<u>16,804</u>	<u>14,835</u>
Cash and Cash Equivalents at End of Period	<u><u>\$3,914</u></u>	<u><u>\$3,237</u></u>	<u><u>\$16,804</u></u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$82,593,000, \$89,984,000 and \$92,140,000 and for income taxes was \$94,440,000, \$60,523,000 and \$100,470,000 in 2003, 2002 and 2001, respectively. Non-cash acquisitions under capital leases were \$1,023,000 and \$22,218,000 in 2002 and 2001, respectively. There were no non-cash capital lease acquisitions in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						<u>2003</u>	<u>2002</u>
						(in thousands)	
COMMON SHAREHOLDER’S EQUITY						<u>\$1,078,047</u>	<u>\$1,018,653</u>
PREFERRED STOCK:							
\$100 Par Value - Authorized 2,250,000 shares							
\$25 Par Value - Authorized 11,200,000 shares							
<u>Series</u>	<u>Call Price</u>	<u>Number of Shares Redeemed</u>			<u>Shares</u>		
	<u>December 31,</u>				<u>Outstanding</u>		
	<u>2003 (a)</u>	<u>Year Ended December 31,</u>			<u>December 31, 2003</u>		
		<u>2003</u>	<u>2002</u>	<u>2001</u>			
Not Subject to Mandatory Redemption - \$100 Par:							
4-1/8%	106.125	-	20	-	55,369	5,537	5,537
4.56%	102	-	-	-	14,412	1,441	1,441
4.12%	102.728	-	6,326	-	11,230	<u>1,123</u>	<u>1,123</u>
Total						<u>8,101</u>	<u>8,101</u>
Subject to Mandatory Redemption - \$100 Par(b):							
5.90% (c)		-	-	-	152,000	15,200	15,200
6-1/4% (c)		-	-	-	192,500	19,250	19,250
6.30% (c)		-	-	-	132,450	13,245	13,245
6-7/8% (d)		15,000	-	-	157,500	<u>15,750</u>	<u>17,250</u>
Total						<u>63,445</u>	<u>64,945</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						54,725	174,245
Installment Purchase Contracts						310,676	310,336
Senior Unsecured Notes						747,873	747,027
Other Long-term Debt (e)						226,085	223,736
Junior Debentures						-	161,718
Less Portion Due Within One Year						<u>(205,000)</u>	<u>(30,000)</u>
Long-term Debt Excluding Portion Due Within One Year						<u>1,134,359</u>	<u>1,587,062</u>
TOTAL CAPITALIZATION						<u>\$2,283,952</u>	<u>\$2,678,761</u>

- (a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
- (b) Sinking fund provisions require the redemption of 67,500 shares in each of 2004, 2005, 2006 and 2007 and 52,500 shares in 2008. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of these due dates. Shares previously purchased may be applied to meet the sinking fund requirement.
- (c) Commencing in 2004 and continuing through 2008 I&M may redeem, at \$100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. The series are callable beginning November 1, 2003 for the 5.90% series, December 1, 2003 for the 6-1/4% series and March 1, 2004 for the 6.30% series at \$100 plus accrued dividends.
- (d) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at \$100 per share. Callable at \$100 per share plus accrued dividends beginning February 1, 2003.
- (e) Represents a liability for SNF disposal including interest payable to the DOE. See Note 7.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
6.10	2003 – November 1	\$-	\$30,000
8.50	2022 – December 15	-	75,000
7.35	2023 – October 1	-	15,000
7.20	2024 – February 1	30,000 (a)	30,000
7.50	2024 – March 1	25,000 (a)	25,000
	Unamortized Discount	<u>(275)</u>	<u>(755)</u>
Total		<u>\$54,725</u>	<u>\$174,245</u>

(a) These bonds will be redeemed in April 2004 and have been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien 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.

Installment Purchase Contracts have been entered in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
City of Lawrenceburg, Indiana:				
	7.00	2015 – April 1	\$-	\$25,000
	(a)	2019 – October 1	25,000	-
	5.90	2019 – November 1	52,000	52,000
City of Rockport, Indiana:				
	7.60	2016 – March 1	-	40,000
	(a)	2025 – April 1	40,000	-
	6.55	2025 – June 1	50,000	50,000
	(b)	2025 – June 1	50,000	50,000
	4.90(c)	2025 – June 1	50,000	50,000
City of Sullivan, Indiana:				
	5.95	2009 – May 1	45,000	45,000
		Unamortized Discount	<u>(1,324)</u>	<u>(1,664)</u>
	Total		<u>\$310,676</u>	<u>\$310,336</u>

- (a) Rate is an annual long-term fixed rate of 2.625% through October 1, 2006. After that date the rate may be a daily or weekly reset rate, commercial paper, auction or other long-term rate as designated by I&M (fixed rate bonds).
- (b) In 2001, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2003 ranged from 0.85% to 1.35% and averaged 1.05%. The auction rate for 2002 ranged from 1.3% to 1.7% and averaged 1.5%.
- (c) Rate is fixed until June 1, 2007 (term rate bonds).

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay 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 generating plants. 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). Interest payments range from every 35 days to semi-annually.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6-7/8	2004 – July 1	\$150,000	\$150,000
6.125	2006 – December 15	300,000	300,000
6.45	2008 – November 10	50,000	50,000
6.375	2012 – November 1	100,000	100,000
6.00	2032 – December 31	150,000	150,000
	Unamortized Discount	<u>(2,127)</u>	<u>(2,973)</u>
	Total	<u>\$747,873</u>	<u>\$747,027</u>

Junior Debentures outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
8.00	2026 – March 31	\$-	\$40,000
7.60	2038 – June 30	-	125,000
	Unamortized Discount	<u>-</u>	<u>(3,282)</u>
	Total	<u>\$ -</u>	<u>\$161,718</u>

At December 31, 2003 future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$205,000
2005	-
2006	365,000
2007	50,000
2008	50,000
Later Years	<u>673,085</u>
Total Principal Amount	1,343,085
Unamortized Discount	<u>(3,726)</u>
Total	<u>\$1,339,359</u>

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to I&M's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to I&M. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA

	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>
			(in thousands)		
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$416,470	\$378,683	\$379,025	\$389,875	\$358,757
Operating Expenses	<u>351,726</u>	<u>336,486</u>	<u>331,347</u>	<u>340,137</u>	<u>304,082</u>
Operating Income	64,744	42,197	47,678	49,738	54,675
Nonoperating Items, Net	(2,660)	5,206	1,248	2,070	(327)
Interest Charges	<u>28,620</u>	<u>26,836</u>	<u>27,361</u>	<u>31,045</u>	<u>28,918</u>
Income Before Cumulative Effect of Accounting Change	33,464	20,567	21,565	20,763	25,430
Cumulative Effect of Accounting Change (Net of Tax)	<u>(1,134)</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	<u><u>\$32,330</u></u>	<u><u>\$20,567</u></u>	<u><u>\$21,565</u></u>	<u><u>\$20,763</u></u>	<u><u>\$25,430</u></u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$1,349,746	\$1,295,619	\$1,128,415	\$1,103,064	\$1,079,048
Accumulated Depreciation and Amortization	<u>381,876</u>	<u>373,638</u>	<u>360,319</u>	<u>338,270</u>	<u>318,799</u>
Net Electric Utility Plant	<u><u>\$967,870</u></u>	<u><u>\$921,981</u></u>	<u><u>\$768,096</u></u>	<u><u>\$764,794</u></u>	<u><u>\$760,249</u></u>
TOTAL ASSETS	<u><u>\$1,221,634</u></u>	<u><u>\$1,188,342</u></u>	<u><u>\$1,022,833</u></u>	<u><u>\$1,516,921</u></u>	<u><u>\$1,007,332</u></u>
Common Stock and Paid-in Capital	\$259,200	\$259,200	\$209,200	\$209,200	\$209,200
Retained Earnings	64,151	48,269	48,833	57,513	67,110
Accumulated Other Comprehensive Income (Loss)	<u>(6,213)</u>	<u>(9,451)</u>	<u>(1,903)</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u><u>\$317,138</u></u>	<u><u>\$298,018</u></u>	<u><u>\$256,130</u></u>	<u><u>\$266,713</u></u>	<u><u>\$276,310</u></u>
Long-term Debt (a)	<u><u>\$487,602</u></u>	<u><u>\$466,632</u></u>	<u><u>\$346,093</u></u>	<u><u>\$330,880</u></u>	<u><u>\$365,782</u></u>
Obligations Under Capital Leases (a)	<u><u>\$5,292</u></u>	<u><u>\$7,248</u></u>	<u><u>\$9,583</u></u>	<u><u>\$14,184</u></u>	<u><u>\$15,141</u></u>
TOTAL CAPITALIZATION AND LIABILITIES	<u><u>\$1,221,634</u></u>	<u><u>\$1,188,342</u></u>	<u><u>\$1,022,833</u></u>	<u><u>\$1,516,921</u></u>	<u><u>\$1,007,332</u></u>

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

KPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. 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 their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

Net Income for 2003 increased \$12 million over 2002 primarily due to improved earnings from system sales and transmission revenues, as well as decreased employee related expenses and maintenance expenses. These improvements were partially offset by net losses from risk management activities included in Nonoperating Income (Expense) that exceeded net gains from risk management activities included in Operating Income.

Operating Income

Operating Income for 2003 increased \$23 million primarily due to:

- Increases in system sales and transmission revenues of \$16 million and an increase in gains from risk management activities of \$7 million.
- An increase in Sales to AEP Affiliates of \$12 million due to strong wholesale sales by the AEP Power Pool.
- An increase in residential and commercial sales of \$4 million over 2002 due to the rate increase in mid 2003 to recover the cost of emission control equipment (see Note 4, "Rate Matters").
- An \$8 million decrease in Maintenance expense due to planned plant outages in 2002. Big Sandy plant Unit 2 was down for the entire fourth quarter of 2002 for planned boiler and electric plant maintenance. In addition, Big Sandy Unit 1 was down for two months in 2002 for boiler maintenance.
- A \$6 million decrease in Other Operation expense primarily due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits recorded in 2002, partially offset by reduced gains from emission allowances.

The increases in Operating Income were partially offset by:

- A decline in industrial sales of \$2 million reflecting the weak economy and the reduced usage by a major customer in 2003.
- An increase in fuel expense of \$9 million due to increased generation based on the increased plant availability at Big Sandy in 2003.
- An increase in purchased power expense of \$10 million necessary to support system sales and Sales to AEP Affiliates. In addition, energy purchases increased from the Rockport Plant based on plant availability, as required by the unit power agreement with AEGCo, an affiliated company. The unit power agreement with AEGCo provides for our purchase of 15% of the total output of the two unit 2,600-MW capacity Rockport Plant.
- An increase in Depreciation and Amortization of \$6 million reflecting the completion and implementation of new capital projects in the third quarter of 2003, as well as the implementation of emission control equipment at the Big Sandy plant in the second quarter of 2003.
- An increase in Income Taxes of \$3 million due to an increase in pre-tax book operating income partially offset by federal and state tax return adjustments.

Other Impacts on Earnings

Nonoperating income decreased \$12 million in 2003 compared to 2002 primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area. The decrease in nonoperating income was partially offset by a \$4 million decrease in nonoperating income taxes resulting primarily from the reduced pre-tax nonoperating book income. Interest Charges increased \$2 million primarily due to an increase in outstanding debt partially offset by lower market interest rates on newly issued debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
Senior Unsecured Debt	Baa2	BBB	BBB

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002.

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, 2003:

	Payments Due by Period (in thousands)				
<u>Contractual Cash Obligations</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Long-term Debt	\$-	\$60,000	\$352,964	\$74,638	\$487,602
Advances from Affiliates	38,096	-	-	-	38,096
Capital Lease Obligations	2,107	2,597	1,041	116	5,861
Unconditional Purchase Obligations (a)	39,658	16,636	-	-	56,294
Noncancellable Operating Leases	<u>1,209</u>	<u>1,877</u>	<u>1,246</u>	<u>1,785</u>	<u>6,117</u>
Total	<u>\$81,070</u>	<u>\$81,110</u>	<u>\$355,251</u>	<u>\$76,539</u>	<u>\$593,970</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$24,998
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(6,682)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	32
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(1,744)
Changes in Fair Value of Risk Management Contracts (e)	461
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	<u>(1,575)</u>
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	15,490
Net Cash Flow Hedge Contracts (g)	126
DETM Assignment (h)	<u>(7,349)</u>
Ending Balance December 31, 2003	<u>\$8,267</u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b)The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
- (h)See Note 17 “Related Party Transactions.”

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
			<u>(in thousands)</u>				
Prices Actively Quoted – Exchange Traded Contracts	\$277	\$(56)	\$7	\$43	\$-	\$-	\$271
Prices Provided by Other External Sources – OTC Broker Quotes (a)	5,405	1,937	1,899	772	388	-	10,401
Prices Based on Models and Other Valuation Methods (b)	<u>(1)</u>	<u>12</u>	<u>754</u>	<u>871</u>	<u>801</u>	<u>2,381</u>	<u>4,818</u>
Total	<u>\$5,681</u>	<u>\$1,893</u>	<u>\$2,660</u>	<u>\$1,686</u>	<u>\$1,189</u>	<u>\$2,381</u>	<u>\$15,490</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Year Ended December 31, 2003

	<u>Domestic Power</u>	<u>Interest Rate (in thousands)</u>	<u>Consolidated</u>
Beginning Balance December 31, 2002	\$(103)	\$425	\$322
Changes in Fair Value (a)	75	-	75
Reclassifications from AOCI to Net Income (b)	<u>110</u>	<u>(87)</u>	<u>23</u>
Ending Balance December 31, 2003	<u>\$82</u>	<u>\$338</u>	<u>\$420</u>

- (a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.
- (b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$466 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$136	\$527	\$220	\$52	\$333	\$1,019	\$364	\$74

VaR Associated with Debt Outstanding

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 \$29 million and \$30 million at December 31, 2003 and 2002, 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 operation or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
<u>OPERATING REVENUES</u>			
Electric Generation, Transmission and Distribution	\$376,662	\$350,719	\$336,659
Sales to AEP Affiliates	<u>39,808</u>	<u>27,964</u>	<u>42,366</u>
TOTAL	<u>416,470</u>	<u>378,683</u>	<u>379,025</u>
<u>OPERATING EXPENSES</u>			
Fuel for Electric Generation	74,148	65,043	70,635
Purchased Electricity for Resale	963	29	86
Purchased Electricity from AEP Affiliates	141,690	133,002	130,204
Other Operation	47,325	52,892	58,275
Maintenance	27,328	35,089	22,444
Depreciation and Amortization	39,309	33,233	32,491
Taxes Other Than Income Taxes	8,788	8,240	7,854
Income Taxes	<u>12,175</u>	<u>8,958</u>	<u>9,358</u>
TOTAL	<u>351,726</u>	<u>336,486</u>	<u>331,347</u>
OPERATING INCOME	64,744	42,197	47,678
Nonoperating Income (Expense)	(4,036)	7,950	10,979
Nonoperating Expenses	1,124	840	9,047
Nonoperating Income Tax Expense (Credit)	(2,500)	1,904	684
Interest Charges	<u>28,620</u>	<u>26,836</u>	<u>27,361</u>
Income Before Cumulative Effect of Accounting Change	33,464	20,567	21,565
Cumulative Effect of Accounting Change (Net of Tax)	<u>(1,134)</u>	<u>-</u>	<u>-</u>
NET INCOME	<u><u>\$32,330</u></u>	<u><u>\$20,567</u></u>	<u><u>\$21,565</u></u>

The common stock of KPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$50,450	\$158,750	\$57,513	\$-	\$266,713
Common Stock Dividends			(30,245)		<u>(30,245)</u>
TOTAL					<u>236,468</u>
<u>COMPREHENSIVE INCOME</u>					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,903)	(1,903)
NET INCOME			21,565		<u>21,565</u>
TOTAL COMPREHENSIVE INCOME					<u>19,662</u>
DECEMBER 31, 2001	\$50,450	\$158,750	\$48,833	\$(1,903)	\$256,130
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(21,131)		<u>(21,131)</u>
TOTAL					<u>284,999</u>
<u>COMPREHENSIVE INCOME</u>					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				2,225	2,225
Minimum Pension Liability				(9,773)	(9,773)
NET INCOME			20,567		<u>20,567</u>
TOTAL COMPREHENSIVE INCOME					<u>13,019</u>
DECEMBER 31, 2002	\$50,450	\$208,750	\$48,269	\$(9,451)	\$298,018
Common Stock Dividends			(16,448)		<u>(16,448)</u>
TOTAL					<u>281,570</u>
<u>COMPREHENSIVE INCOME</u>					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				98	98
Minimum Pension Liability				3,140	3,140
NET INCOME			32,330		<u>32,330</u>
TOTAL COMPREHENSIVE INCOME					<u>35,568</u>
DECEMBER 31, 2003	<u>\$50,450</u>	<u>\$208,750</u>	<u>\$64,151</u>	<u>\$(6,213)</u>	<u>\$317,138</u>

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$457,341	\$275,121
Transmission	381,354	373,639
Distribution	425,688	414,281
General	68,041	67,449
Construction Work in Progress	<u>17,322</u>	<u>165,129</u>
TOTAL	1,349,746	1,295,619
Accumulated Depreciation and Amortization	<u>381,876</u>	<u>373,638</u>
TOTAL – NET	<u>967,870</u>	<u>921,981</u>
<u>OTHER PROPERTY AND INVESTMENTS</u>		
Non-Utility Property, Net	5,423	5,477
Other Investments	<u>1,022</u>	<u>1,427</u>
TOTAL	<u>6,445</u>	<u>6,904</u>
<u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	886	2,304
Accounts Receivable:		
Customers	21,177	24,716
Affiliated Companies	25,327	23,802
Accrued Unbilled Revenues	5,534	5,301
Miscellaneous	97	217
Allowance for Uncollectible Accounts	(736)	(192)
Fuel	9,481	10,817
Materials and Supplies	16,585	16,127
Accrued Tax Benefit	-	1,253
Risk Management Assets	16,200	24,261
Margin Deposits	2,660	320
Prepayments and Other	<u>1,696</u>	<u>1,866</u>
TOTAL	<u>98,907</u>	<u>110,792</u>
<u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	99,828	87,261
Other Regulatory Assets	13,971	14,715
Long-term Risk Management Assets	16,134	29,871
Deferred Property Taxes	6,847	6,300
Other Deferred Charges	<u>11,632</u>	<u>10,518</u>
TOTAL	<u>148,412</u>	<u>148,665</u>
TOTAL ASSETS	<u>\$1,221,634</u>	<u>\$1,188,342</u>

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	<u>(in thousands)</u>	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – \$50 Par Value:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	\$50,450	\$50,450
Paid-in Capital	208,750	208,750
Retained Earnings	64,151	48,269
Accumulated Other Comprehensive Income (Loss)	<u>(6,213)</u>	<u>(9,451)</u>
Total Common Shareholder's Equity	<u>317,138</u>	<u>298,018</u>
Long-term Debt:		
Nonaffiliated	427,602	391,632
Affiliated	<u>60,000</u>	<u>60,000</u>
Total Long-term Debt	<u>487,602</u>	<u>451,632</u>
TOTAL	<u>804,740</u>	<u>749,650</u>
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Affiliated	-	15,000
Advances from Affiliates	38,096	23,386
Accounts Payable:		
General	22,802	46,515
Affiliated Companies	22,648	44,035
Customer Deposits	9,894	8,048
Taxes Accrued	7,329	-
Interest Accrued	6,915	6,471
Risk Management Liabilities	11,704	17,803
Obligations Under Capital Leases	1,743	2,155
Other	<u>8,628</u>	<u>12,167</u>
TOTAL	<u>129,759</u>	<u>175,580</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	212,121	178,313
Regulatory Liabilities:		
Asset Removal Costs	26,140	-
Deferred Investment Tax Credits	7,955	9,165
Other Regulatory Liabilities	10,591	12,152
Long-term Risk Management Liabilities	12,363	11,488
Obligations Under Capital Leases	3,549	5,093
Deferred Credits and Other	<u>14,416</u>	<u>46,901</u>
TOTAL	<u>287,135</u>	<u>263,112</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$1,221,634</u>	<u>\$1,188,342</u>

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$32,330	\$20,567	\$21,565
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Cumulative Effect of Accounting Change	1,134	-	-
Depreciation and Amortization	39,309	33,233	32,491
Deferred Income Taxes	20,107	9,839	6,293
Deferred Investment Tax Credits	(1,210)	(1,240)	(1,251)
Deferred Fuel Costs, Net	233	2,998	(4,707)
Mark-to-Market of Risk Management Contracts	15,112	(12,267)	(1,454)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	2,445	(9,332)	24,799
Fuel, Materials and Supplies	878	882	(7,658)
Accounts Payable	(45,100)	44,529	(22,942)
Taxes Accrued	8,582	(11,558)	(1,580)
Change in Other Assets	(16,588)	(21,491)	(2,762)
Change in Other Liabilities	4,565	16,161	(9,446)
Net Cash Flows From Operating Activities	<u>61,797</u>	<u>72,321</u>	<u>33,348</u>
INVESTING ACTIVITIES			
Construction Expenditures	(81,707)	(178,700)	(37,206)
Proceeds from Sales of Property and Other	967	217	216
Net Cash Flow Used for Investing Activities	<u>(80,740)</u>	<u>(178,483)</u>	<u>(36,990)</u>
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	-	50,000	-
Issuance of Long-term Debt – Nonaffiliated	74,263	274,964	-
Issuance of Long-term Debt – Affiliated	-	-	75,000
Retirement of Long-term Debt – Nonaffiliated	(40,000)	(154,500)	(60,000)
Retirement of Long-term Debt – Affiliated	(15,000)	-	-
Change in Advances to/from Affiliates, Net	14,710	(42,814)	18,564
Dividends Paid	(16,448)	(21,131)	(30,245)
Net Cash Flows From Financing Activities	<u>17,525</u>	<u>106,519</u>	<u>3,319</u>
Net Increase (Decrease) in Cash and Cash Equivalents	(1,418)	357	(323)
Cash and Cash Equivalents at Beginning of Period	<u>2,304</u>	<u>1,947</u>	<u>2,270</u>
Cash and Cash Equivalents at End of Period	<u>\$886</u>	<u>\$2,304</u>	<u>\$1,947</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$26,988,000, \$25,176,000 and \$27,090,000 in 2003, 2002 and 2001, respectively. Cash (received) paid for income taxes was \$(17,574,000), \$13,041,000 and \$7,549,000 in 2003, 2002 and 2001, respectively. Noncash acquisitions under capital leases were \$22,000 and \$817,000 in 2002 and 2001, respectively. There were no non-cash capital lease acquisitions in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	<u>\$317,138</u>	<u>\$298,018</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):		
Senior Unsecured Notes	427,602	352,508
Notes Payable	60,000	75,000
Junior Debentures	-	39,124
Less Portion Due Within One Year	<u>-</u>	<u>(15,000)</u>
Long-term Debt Excluding Portion Due Within One Year	<u>487,602</u>	<u>451,632</u>
TOTAL CAPITALIZATION	<u>\$804,740</u>	<u>\$749,650</u>

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
6.91	2007 – October 1	\$48,000	\$48,000
6.45	2008 – November 10	30,000	30,000
5.50	2007 – July 1	125,000	125,000
4.31	2007 – November 12	80,400	80,400
4.37	2007 – December 12	69,564	69,564
5.625	2032 – December 31	75,000	-
	Unamortized Discount	(362)	(456)
Total		<u>\$427,602</u>	<u>\$352,508</u>

Notes Payable to parent company were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
4.336	2003 – May 15	\$-	\$15,000
6.501	2006 – May 15	60,000	60,000
Total		<u>\$60,000</u>	<u>\$75,000</u>

Junior Debentures outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u> (in thousands)
8.72	2025 – June 30	\$-	\$40,000
	Unamortized Discount	-	(876)
Total		<u>\$ -</u>	<u>\$39,124</u>

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

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$-
2005	-
2006	60,000
2007	322,964
2008	30,000
Later Years	75,000
Total Principal Amount	487,964
Unamortized Discount	(362)
Total	<u>\$487,602</u>

KENTUCKY POWER COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to KPCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to KPCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of
Directors of Kentucky Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Kentucky Power Company as of December 31, 2003 and 2002, and the related statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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 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.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

OHIO POWER COMPANY CONSOLIDATED

**OHIO POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$2,244,653	\$2,113,125	\$2,098,105	\$2,140,331	\$1,978,826
Operating Expenses	<u>1,884,986</u>	<u>1,814,796</u>	<u>1,857,395</u>	<u>1,913,504</u>	<u>1,689,997</u>
Operating Income	359,667	298,329	240,710	226,827	288,829
Nonoperating Items, Net	(2,172)	5,376	18,686	(5,004)	7,000
Interest Charges	<u>106,464</u>	<u>83,682</u>	<u>93,603</u>	<u>119,210</u>	<u>83,672</u>
Income Before Extraordinary Item And Cumulative Effect	251,031	220,023	165,793	102,613	212,157
Extraordinary Loss (Net of Tax)	-	-	(18,348)	(18,876)	-
Cumulative Effect of Accounting Changes (Net of Tax)	<u>124,632</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	375,663	220,023	147,445	83,737	212,157
Preferred Stock					
Dividend Requirements	<u>1,098</u>	<u>1,258</u>	<u>1,258</u>	<u>1,266</u>	<u>1,417</u>
Earnings Applicable To Common Stock	<u>\$374,565</u>	<u>\$218,765</u>	<u>\$146,187</u>	<u>\$82,471</u>	<u>\$210,740</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$6,531,315	\$5,685,826	\$5,390,576	\$5,577,631	\$5,400,917
Accumulated Depreciation	<u>2,485,947</u>	<u>2,469,837</u>	<u>2,360,857</u>	<u>2,678,606</u>	<u>2,540,445</u>
Net Electric Utility Plant	<u>\$4,045,368</u>	<u>\$3,215,989</u>	<u>\$3,029,719</u>	<u>\$2,899,025</u>	<u>\$2,860,472</u>
TOTAL ASSETS	<u>\$5,374,518</u>	<u>\$4,554,023</u>	<u>\$4,485,787</u>	<u>\$6,279,499</u>	<u>\$4,756,425</u>
Common Stock and Paid-in Capital	\$783,685	\$783,684	\$783,684	\$783,684	\$783,577
Retained Earnings	729,147	522,316	401,297	398,086	587,424
Accumulated Other Comprehensive Income (Loss)	<u>(48,807)</u>	<u>(72,886)</u>	<u>(196)</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u>\$1,464,025</u>	<u>\$1,233,114</u>	<u>\$1,184,785</u>	<u>\$1,181,770</u>	<u>\$1,371,001</u>
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	\$16,645	\$16,648	\$16,648	\$16,648	\$16,937
Subject to Mandatory Redemption (a)	<u>7,250</u>	<u>8,850</u>	<u>8,850</u>	<u>8,850</u>	<u>8,850</u>
Total Cumulative Preferred Stock	<u>\$23,895</u>	<u>\$25,498</u>	<u>\$25,498</u>	<u>\$25,498</u>	<u>\$25,787</u>
Long-term Debt (a)	<u>\$2,039,940</u>	<u>\$1,067,314</u>	<u>\$1,203,841</u>	<u>\$1,195,493</u>	<u>\$1,151,511</u>
Obligations Under Capital Leases (a)	<u>\$34,688</u>	<u>\$65,626</u>	<u>\$80,666</u>	<u>\$116,581</u>	<u>\$136,543</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$5,374,518</u>	<u>\$4,554,023</u>	<u>\$4,485,787</u>	<u>\$6,279,499</u>	<u>\$4,756,425</u>

(a) Including portion due within one year.

OHIO POWER COMPANY CONSOLIDATED MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

OPCo is a public utility engaged in the generation and purchase of electric power and the subsequent sale, transmission and distribution of that power to approximately 704,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We also supply and market electric power at wholesale to other electric utility companies, municipalities and electric cooperatives. We, as a member of the AEP Power Pool, share in the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Effective July 1, 2003, we consolidated JMG Funding, LP (JMG) as a result of the implementation of FIN 46. OPCo now 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 Note 2, "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes," and Note 15, "Leases," for further discussion of the effects of FIN 46.

Results of Operations

During 2003, Net Income increased \$156 million including a \$125 million Cumulative Effect of Accounting Changes in the first quarter of 2003 (see Note 2). Income Before Cumulative Effect of Accounting Changes increased \$31 million primarily due to increased revenues which were allocated to us from sales made to third parties by the AEP Power Pool.

During 2002, Income Before Extraordinary Item increased \$54 million due to reductions in operating expenses, predominantly fuel, and interest charges.

2003 Compared to 2002

Operating Income

Operating Income increased \$61 million for the year 2003 compared with 2002 due to:

- A \$22 million increase in revenues from non-affiliated system sales and a \$119 million increase in Sales to AEP Affiliates. The increase in non-affiliated system sales is primarily the result of an 8.9% increase in the price per MWH in 2003. The increase in affiliated sales is the result of optimizing our generation capacity and selling our excess generated power to the AEP Power Pool.
- A \$47 million decrease in Other Operation expense. This decrease was primarily due to a \$23 million decrease in rent expense associated with the OPCo consolidation of JMG. OPCo now records the depreciation, interest and other expenses of JMG and eliminates operating lease expense against JMG's lease revenues (there was no change in overall net income due to the consolidation of JMG). In addition, operation expenses decreased due to a \$7 million pre-tax adjustment to the workers' compensation reserve related to coal companies sold in July 2001, a \$9 million decrease in expense related to post-employment benefits and an \$8 million reduction in employee salary expenses.

The increase in Operating Income was partially offset by:

- An increase in Fuel for Electric Generation of \$32 million as a result of a 9.7% increase in MWH generated.
- An increase in Purchased Electricity from AEP Affiliates of \$20 million resulting from a 31% volume increase in MWHs purchased from the AEP Power Pool.
- A \$30 million increase in Maintenance expenses. The increase in 2003 is primarily due to increased boiler overhaul costs for planned and forced outages coupled with increased expense in maintaining overhead lines due to storm damage in Southern Ohio.
- An increase in Depreciation and Amortization associated with the OPCo consolidation of JMG. Depreciation expense related to the assets owned by JMG are now consolidated with OPCo.
- An increase in Income Taxes of \$32 million as a result of an increase in pre-tax operating book income and tax return adjustments.

Other Impacts of Earnings

Nonoperating Income decreased \$34 million for the year 2003 compared to 2002 primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area.

Nonoperating Income Tax Expense decreased \$26 million as a result of a decrease in pre-tax nonoperating book income and changes related to consolidated tax savings.

Interest charges increased \$23 million due primarily to the consolidation of JMG and its associated debt along with replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2002 Compared to 2001

Operating Income

Operating Income increased \$58 million from the year 2001 to the year 2002 primarily due to:

- A \$61 million increase in nonaffiliated revenues resulting from a 39% increase in cooling degree days during the summer months along with a 32% increase in the heating degree days during the fall season. This reflects a return to more normal weather conditions since 2001 weather was abnormally mild.
- A \$102 million decrease in Fuel for Electric Generation expense. This reflects a reduction of 19% in average cost of fuel for generation, offset in part by a slight increase in MWH generated. The decrease in fuel costs are the result of purchasing coal at lower prices on the open market in 2002 instead of affiliated company coal.

The increase in Operating Income was partially offset by:

- A \$46 million decrease in Sales to AEP Affiliates. This decrease is due to a 15% decrease in price, reflective of lower average fuel cost, while MWH sales rose slightly.
- A \$13 million increase in Purchased Electricity for Resale and Purchased Electricity from AEP Affiliates expenses. This was the result of an 11% increase in MWH sales and an 18% increase of MWH purchased from affiliates, partially offset by a decrease in price.
- A \$16 million increase in Taxes Other Than Income Taxes as a result of increases in state excise tax created from a change in the base tax calculation.
- A \$12 million increase in both federal and state tax expenses. Federal taxes increased due to higher pre-tax operating income offset in part by changes in certain book/tax timing differences accounted for on a flow-thru basis. State taxes increased predominately as a result of the State of Ohio's tax legislation revision involving utility deregulation.

Other Impacts on Earnings

Nonoperating Expenses decreased \$25 million during 2002 due to reductions in variable incentive compensation expenses associated with risk management activities.

Nonoperating Income Tax Expense increased \$20 million as a result of a favorable tax benefit recognized in 2001 from the sale of the Ohio Coal companies.

Interest Charges decreased \$10 million due primarily to a decrease in the outstanding balances of long-term debt, the refinancing of debt at favorable interest rates and a reduction in short-term interest rates.

Extraordinary Loss

In the second quarter of 2001, an extraordinary loss of \$18 million net of tax was recorded to write-off prepaid Ohio excise taxes stranded by Ohio deregulation (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	A3	BBB	A-
Senior Unsecured Debt	A3	BBB	BBB+

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows years ended December 31, 2003, 2002 and 2001 were as follows:

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
Cash and cash equivalents at beginning of period	<u>\$5,285</u>	<u>\$8,848</u>	<u>\$31,393</u>
Cash flows from (used for):			
Operating activities	373,443	478,973	86,756
Investing activities	(237,011)	(348,298)	(359,908)
Financing activities	<u>(83,467)</u>	<u>(134,238)</u>	<u>250,607</u>
Net increase (decrease) in cash and cash equivalents	<u>52,965</u>	<u>(3,563)</u>	<u>(22,545)</u>
Cash and cash equivalents at end of period	<u><u>\$58,250</u></u>	<u><u>\$5,285</u></u>	<u><u>\$8,848</u></u>

Operating Activities

Cash flows from operating activities for the year 2003 decreased \$106 million compared to the year 2002 as they were adversely impacted primarily by significant reductions of accounts payable balances partially associated with a wind down of risk management activities in the current year.

Cash flows from operating activities for the year 2002 compared to the year 2001 increased \$392 million as they were adversely impacted primarily by significant increases in Employee Benefits and Other Noncurrent Liabilities.

Investing Activities

Cash flows used for investing activities were reduced in the year 2003 compared with the year 2002 due primarily to a \$110 million decrease in construction expenditures.

Cash flows used for investing activities remained relatively consistent from the year 2001 to the year 2002.

Financing Activities

Cash flows used for financing activities for the year of 2003 compared to the year 2002 used \$51 million less primarily due to the retirement and restructuring of our long-term and short-term debt during 2003. We retired \$300 million of Long-term Debt to Affiliated Companies and \$275 million of Short-term Debt to Affiliated Companies with the proceeds of two Senior Unsecured Notes at \$250 million each. In addition we issued two series of Senior Unsecured Notes, each in the amount of \$225 million in July 2003.

Cash flows used for financing activities for the year 2002 compared to the year 2001 increased \$385 million. This is primarily due to a decrease in the change in Advances to/from Affiliates, net during 2002.

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, 2003:

	Payments Due by Period (in millions)				
<u>Contractual Cash Obligations</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Long-term Debt	\$432	\$25	\$73	\$1,510	\$2,040
Short-term Debt	26	-	-	-	26
Preferred Stock Subject to Mandatory Redemption	2	4	1	-	7
Capital Lease Obligations	11	16	9	5	41
Unconditional Purchase Obligations (a)	626	917	511	578	2,632
Noncancellable Operating Leases	<u>13</u>	<u>23</u>	<u>22</u>	<u>67</u>	<u>125</u>
Total	<u>\$1,110</u>	<u>\$985</u>	<u>\$616</u>	<u>\$2,160</u>	<u>\$4,871</u>

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

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 and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
<u>Other Commercial Commitments</u>	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	<u>Total</u>
Standby Letters of Credit (a)	\$5	\$-	\$-	\$-	\$5
Other Commercial Commitments (b)	<u>14</u>	<u>14</u>	<u>-</u>	<u>-</u>	<u>28</u>
Total Commercial Commitments	<u>\$19</u>	<u>\$14</u>	<u>\$-</u>	<u>\$-</u>	<u>\$33</u>

- (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 the ordinary course of business. AEP holds all assets of OPCo as collateral. There is no recourse to third parties in the event these letters of credit are drawn.
- (b) We have entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, we have the option to run the plant until December 31, 2005, taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at \$1.2 million per month. For the remainder of the 30-year contract term, we will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity.

Other

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to AEP. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by

Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated 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 with debt financing up to \$494 million and equity up to \$31 million from investors with no relationship to AEP or any of AEP's subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

Another AEP subsidiary is the construction agent for Juniper. They expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and AEP will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, AEP has the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. AEP has the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, AEP may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if AEP has arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, AEP 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, AEP may be required to make a payment (not to exceed \$396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that AEP would not be required to make any payment if AEP has made the additional rental prepayment described below. AEP has guaranteed the performance of our subsidiaries to Juniper during the lease term. Because AEP now reports the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the \$396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled \$496 million, and total costs for the completed Facility are currently expected to be approximately \$525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately \$18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to \$396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected \$396 million of the \$496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is \$396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of \$496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to 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 non-conforming.

OPCo entered into an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols related to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately \$17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

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 "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$94,106
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(38,249)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	106
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,159)
Changes in Fair Value of Risk Management Contracts (e)	2,134
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	<u>53,938</u>
Net Cash Flow Hedge Contracts (g)	412
DETM Assignment (h)	<u>(24,055)</u>
Ending Balance December 31, 2003	<u><u>\$30,295</u></u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g)“Net Cash Flow Hedge Contracts” (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
- (h) See Note 17 “Related Party Transactions.”

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actively Quoted – Exchange Traded Contracts	\$908	\$(183)	\$22	\$142	\$-	\$-	\$889
Prices Provided by Other External Sources – OTC Broker Quotes (a)	20,921	6,344	6,221	2,530	1,269	-	37,285
Prices Based on Models and Other Valuation Methods (b)	<u>(4)</u>	<u>26</u>	<u>2,468</u>	<u>2,853</u>	<u>2,623</u>	<u>7,798</u>	<u>15,764</u>
Total	<u>\$21,825</u>	<u>\$6,187</u>	<u>\$8,711</u>	<u>\$5,525</u>	<u>\$3,892</u>	<u>\$7,798</u>	<u>\$53,938</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Year Ended December 31, 2003

	<u>Domestic Power</u>	<u>Foreign Currency</u> (in thousands)	<u>Consolidated</u>
Beginning Balance December 31, 2002	\$(354)	\$(384)	\$(738)
Changes in Fair Value (a)	256	-	256
Reclassifications from AOCI to Net Income (b)	<u>366</u>	<u>13</u>	<u>379</u>
Ending Balance December 31, 2003	<u><u>\$268</u></u>	<u><u>\$(371)</u></u>	<u><u>\$(103)</u></u>

- (a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.
- (b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$1,231 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$444	\$1,724	\$722	\$172	\$1,150	\$3,521	\$1,259	\$255

VaR Associated with Debt Outstanding

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 \$214 million and \$34 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

**OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001**

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,660,375	\$1,647,923	\$1,586,739
Sales to AEP Affiliates	<u>584,278</u>	<u>465,202</u>	<u>511,366</u>
TOTAL	<u>2,244,653</u>	<u>2,113,125</u>	<u>2,098,105</u>
OPERATING EXPENSES			
Fuel for Electric Generation	616,680	584,730	686,568
Purchased Electricity for Resale	63,486	67,385	63,441
Purchased Electricity from AEP Affiliates	90,821	71,154	62,585
Other Operation	369,087	416,533	400,790
Maintenance	166,438	136,609	142,878
Depreciation and Amortization	257,417	248,557	239,982
Taxes Other Than Income Taxes	175,043	176,247	159,778
Income Taxes	<u>146,014</u>	<u>113,581</u>	<u>101,373</u>
TOTAL	<u>1,884,986</u>	<u>1,814,796</u>	<u>1,857,395</u>
OPERATING INCOME	359,667	298,329	240,710
Nonoperating Income	24,495	58,289	76,341
Nonoperating Expenses	34,282	34,903	60,035
Nonoperating Income Tax Expense (Credit)	(7,615)	18,010	(2,380)
Interest Charges	<u>106,464</u>	<u>83,682</u>	<u>93,603</u>
Income Before Extraordinary Item and Cumulative Effect	251,031	220,023	165,793
Extraordinary Loss (Net of Tax)	-	-	(18,348)
Cumulative Effect of Accounting Changes (Net of Tax)	<u>124,632</u>	<u>-</u>	<u>-</u>
NET INCOME	375,663	220,023	147,445
Preferred Stock Dividend Requirements	<u>1,098</u>	<u>1,258</u>	<u>1,258</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$374,565</u>	<u>\$218,765</u>	<u>\$146,187</u>

The common stock of OPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$321,201	\$462,483	\$398,086	\$-	\$1,181,770
Common Stock Dividends			(142,976)		(142,976)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL					<u>1,037,536</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(196)	(196)
NET INCOME			147,445		<u>147,445</u>
TOTAL COMPREHENSIVE INCOME					<u>147,249</u>
DECEMBER 31, 2001	<u>\$321,201</u>	<u>\$462,483</u>	<u>\$401,297</u>	<u>\$(196)</u>	<u>\$1,184,785</u>
Common Stock Dividends			(97,746)		(97,746)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL					<u>1,085,781</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(542)	(542)
Minimum Pension Liability				(72,148)	(72,148)
NET INCOME			220,023		<u>220,023</u>
TOTAL COMPREHENSIVE INCOME					<u>147,333</u>
DECEMBER 31, 2002	<u>\$321,201</u>	<u>\$462,483</u>	<u>\$522,316</u>	<u>\$(72,886)</u>	<u>\$1,233,114</u>
Common Stock Dividends			(167,734)		(167,734)
Preferred Stock Dividends			(1,098)		(1,098)
Capital Stock Gains		1			1
TOTAL					<u>1,064,283</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				635	635
Minimum Pension Liability				23,444	23,444
NET INCOME			375,663		<u>375,663</u>
TOTAL COMPREHENSIVE INCOME					<u>399,742</u>
DECEMBER 31, 2003	<u>\$321,201</u>	<u>\$462,484</u>	<u>\$729,147</u>	<u>\$(48,807)</u>	<u>\$1,464,025</u>

See Notes to Respective Financial Statements beginning on page L-1.

**OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS**

ASSETS

December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$4,029,515	\$3,116,825
Transmission	938,805	905,829
Distribution	1,156,886	1,114,600
General	245,434	260,153
Construction Work in Progress	<u>160,675</u>	<u>288,419</u>
Total	6,531,315	5,685,826
Accumulated Depreciation and Amortization	<u>2,485,947</u>	<u>2,469,837</u>
TOTAL – NET	<u>4,045,368</u>	<u>3,215,989</u>
<u>OTHER PROPERTY AND INVESTMENTS</u>		
Non-Utility Property, Net	29,291	29,037
Other	<u>24,264</u>	<u>32,649</u>
TOTAL	<u>53,555</u>	<u>61,686</u>
<u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	58,250	5,285
Advances to Affiliates	67,918	-
Accounts Receivable:		
Customers	100,960	113,207
Affiliated Companies	120,532	124,244
Miscellaneous	736	1,174
Allowance for Uncollectible Accounts	(789)	(909)
Fuel	77,725	87,409
Materials and Supplies	92,136	85,379
Risk Management Assets	56,265	91,872
Margin Deposits	9,296	1,636
Prepayments and Other	<u>33,104</u>	<u>10,683</u>
TOTAL	<u>616,133</u>	<u>519,980</u>
<u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	169,605	165,106
Transition Regulatory Assets	310,035	375,409
Unamortized Loss on Reacquired Debt	10,172	4,899
Other	22,506	23,227
Long-term Risk Management Assets	52,825	103,230
Deferred Property Taxes	67,469	66,621
Deferred Charges and Other Assets	<u>26,850</u>	<u>17,876</u>
TOTAL	<u>659,462</u>	<u>756,368</u>
TOTAL ASSETS	<u>\$5,374,518</u>	<u>\$4,554,023</u>

See Notes to Respective Financial Statements beginning on page L-1.

**OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002**

	<u>2003</u>	<u>2002</u>
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	\$321,201	\$321,201
Paid-in Capital	462,484	462,483
Retained Earnings	729,147	522,316
Accumulated Other Comprehensive Income (Loss)	<u>(48,807)</u>	<u>(72,886)</u>
Total Common Shareholder's Equity	1,464,025	1,233,114
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>16,645</u>	<u>16,648</u>
Total Shareholder's Equity	1,480,670	1,249,762
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	7,250	8,850
Long-term Debt:		
Nonaffiliated	1,608,086	677,649
Affiliated	<u>-</u>	<u>240,000</u>
Total Long-term Debt	<u>1,608,086</u>	<u>917,649</u>
TOTAL	<u>3,096,006</u>	<u>2,176,261</u>
Minority Interest	<u>16,314</u>	<u>-</u>
CURRENT LIABILITIES		
Short-term Debt – General	25,941	-
Short-term Debt – Affiliates	-	275,000
Long-term Debt Due Within One Year – Nonaffiliated	431,854	89,665
Long-term Debt Due Within One Year – Affiliated	-	60,000
Advances from Affiliates	-	129,979
Accounts Payable:		
General	104,874	170,563
Affiliated Companies	101,758	145,718
Customer Deposits	17,308	12,969
Taxes Accrued	132,793	111,778
Interest Accrued	45,679	18,809
Risk Management Liabilities	38,318	61,839
Obligations Under Capital Leases	9,624	14,360
Other	<u>71,642</u>	<u>80,608</u>
TOTAL	<u>979,791</u>	<u>1,171,288</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	933,582	794,387
Regulatory Liabilities:		
Asset Removal Costs	101,160	-
Deferred Investment Tax Credits	15,641	18,748
Other	3	1,237
Long-term Risk Management Liabilities	40,477	39,702
Deferred Credits	23,222	27,719
Obligations Under Capital Leases	25,064	51,266
Asset Retirement Obligations	42,656	-
Other	<u>100,602</u>	<u>273,415</u>
TOTAL	<u>1,282,407</u>	<u>1,206,474</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$5,374,518</u>	<u>\$4,554,023</u>

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	\$375,663	\$220,023	\$147,445
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Cumulative Effect of Accounting Changes	(124,632)	-	-
Depreciation and Amortization	257,417	248,557	252,123
Deferred Income Taxes	24,482	46,010	215,833
Deferred Investment Tax Credits	(3,107)	(3,177)	(3,289)
Extraordinary Loss	-	-	18,348
Mark-to-Market of Risk Management Contracts	60,064	(28,693)	(59,833)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	16,335	14,571	51,640
Fuel, Materials and Supplies	2,927	704	4,852
Accrued Utility Revenues	(20,301)	3,081	264
Prepayments and Other	(13,096)	8,783	12,017
Accounts Payable	(173,218)	8,704	9,887
Customer Deposits	4,339	7,517	(34,284)
Taxes Accrued	21,015	(14,992)	(96,331)
Interest Accrued	21,533	1,130	(2,779)
Employee Benefits and Other Noncurrent Liabilities	(75,822)	110,298	(392,026)
Deferred Property Taxes	(855)	(1,818)	21,652
Change in Other Assets	(23,302)	(7,441)	46,162
Change in Other Liabilities	24,001	(134,284)	(104,925)
Net Cash Flows From Operating Activities	<u>373,443</u>	<u>478,973</u>	<u>86,756</u>
INVESTING ACTIVITIES			
Construction Expenditures	(244,312)	(354,797)	(344,571)
Proceeds from Sale of Property and Other	7,301	6,499	16,778
Investment in Coal Companies	-	-	(32,115)
Net Cash Flows Used For Investing Activities	<u>(237,011)</u>	<u>(348,298)</u>	<u>(359,908)</u>
FINANCING ACTIVITIES			
Issuance of Long-term Debt	988,914	-	-
Issuance of Long-term Debt – Affiliated	-	-	300,000
Change in Advances to/from Affiliates, Net	(197,897)	(170,234)	392,699
Change in Short-term Debt, Net	(671)	-	-
Change in Short-term Debt – Affiliates Net	(275,000)	275,000	-
Retirement of Long-term Debt – Nonaffiliated	(128,378)	(140,000)	(297,858)
Retirement of Long-term Debt – Affiliated	(300,000)	-	-
Retirement of Cumulative Preferred Stock	(1,603)	-	-
Dividends Paid on Common Stock	(167,734)	(97,746)	(142,976)
Dividends Paid on Cumulative Preferred Stock	(1,098)	(1,258)	(1,258)
Net Cash Flows From (Used For) Financing Activities	<u>(83,467)</u>	<u>(134,238)</u>	<u>250,607</u>
Net Increase (Decrease) in Cash and Cash Equivalents	52,965	(3,563)	(22,545)
Cash and Cash Equivalents at Beginning of Period	<u>5,285</u>	<u>8,848</u>	<u>31,393</u>
Cash and Cash Equivalents at End of Period	<u>\$58,250</u>	<u>\$5,285</u>	<u>\$8,848</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was \$77,170,000, \$81,041,000 and \$94,747,000 and for income taxes was \$98,923,000, \$105,058,000 and \$(22,417,000) in 2003, 2002 and 2001, respectively.

Noncash acquisitions under capital leases were \$106,000 and \$2,380,000 in 2002 and 2001, respectively. There were no noncash capital lease acquisitions in 2003. Noncash activity in 2003 included an increase in assets and liabilities of \$469.6 million resulting from the consolidation of JMG (see Note 2).

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						<u>2003</u>	<u>2002</u>
						(in thousands)	
COMMON SHAREHOLDER’S EQUITY						<u>\$1,464,025</u>	<u>\$1,233,114</u>
PREFERRED STOCK:							
\$100 Par Value - Authorized 3,762,403 shares							
\$25 Par Value - Authorized 4,000,000 shares							
<u>Series</u>	<u>Call Price</u> <u>December 31,</u> <u>2003 (a)</u>	<u>Number of Shares Redeemed</u> <u>Year Ended December 31,</u>			<u>Shares</u> <u>Outstanding</u> <u>December 31, 2003</u>		
		<u>2003</u>	<u>2002</u>	<u>2001</u>			
Not Subject to Mandatory Redemption-\$100 Par:							
4.08%	\$103	-	-	-	14,595	1,460	1,460
4.20%	103.20	-	-	-	22,824	2,282	2,282
4.40%	104	-	-	-	31,512	3,151	3,151
4-1/2%	110	23	-	-	97,523	<u>9,752</u>	<u>9,755</u>
Total						<u>16,645</u>	<u>16,648</u>
Subject to Mandatory Redemption-\$100 Par (b):							
5.90% (c)	\$-	-	-	-	72,500	7,250	7,250
6.02%	-	11,000	-	-	-	-	1,100
6.35%	-	5,000	-	-	-	<u>-</u>	<u>500</u>
Total						<u>7,250</u>	<u>8,850</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						9,950	136,633
Installment Purchase Contracts						539,406	233,340
Senior Unsecured Notes						1,343,706	397,341
Notes Payable – Nonaffiliated						146,878	-
Notes Payable – Affiliated						-	300,000
Less Portion Due Within One Year						<u>(431,854)</u>	<u>(149,665)</u>
Long-term Debt Excluding Portion Due Within One Year						<u>1,608,086</u>	<u>917,649</u>
TOTAL CAPITALIZATION						<u>\$3,096,006</u>	<u>\$2,176,261</u>

- (a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
- (b) Sinking fund provisions require the redemption of 35,000 shares in 2003 and 57,500 shares in each of 2004, 2005, 2006 and 2007. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due dates. Shares previously purchased may be applied to the sinking fund requirement. At the company's option, all shares are redeemable at \$100 per share plus accrued and unpaid dividends with at least 30 days notice beginning on or after November 1, 2003 for the 5.90% series, October 1, 2003 for the 6.02% series, and April 1, 2003 for the 6.35% series.
- (c) Commencing in 2004 and continuing through the year 2008, a sinking fund for the 5.90% cumulative preferred stock will require the redemption of 22,500 shares each year and the redemption of the remaining shares outstanding on January 1, 2009, in each case at \$100 per share. Shares previously redeemed may be applied to meet sinking fund requirements.

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6.75	2003 – April 1	\$-	\$29,850
6.55	2003 – October 1	-	27,315
6.00	2003 – November 1	-	12,500
6.15	2003 – December 1	-	20,000
7.75	2023 – April 1	-	5,000
7.375	2023 – October 1	-	20,250
7.10	2023 – November 1	-	12,000
7.30	2024 – April 1 (a)	10,000	10,000
	Unamortized Discount	<u>(50)</u>	<u>(282)</u>
Total		<u>\$9,950</u>	<u>\$136,633</u>

(a) This bond will be redeemed in April 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien 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.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
Mason County, West Virginia:			
5.45	2016 – December 1	\$50,000	\$50,000
Marshall County, West Virginia:			
5.45	2014 – July 1	50,000	50,000
5.90	2022 – April 1	35,000	35,000
6.85	2022 – June 1	50,000 (a)	50,000
(b)	2022 – June 1	50,000	-
Ohio Air Quality Development Authority:			
5.15	2026 – May 1	50,000	50,000
5.5625	2022 – October 1	19,565 (c)	-
5.5625	2023 – January 1	19,565 (c)	-
(d)	2028 – April 1	40,000 (c)	-
(e)	2028 – April 1	40,000 (c)	-
6.3750	2029 – January 1	51,000 (c)	-
6.3750	2029 – April 1	51,000 (c)	-
(d)	2029 – April 1	18,000 (c)	-
(e)	2029 – April 1	18,000 (c)	-
	Unamortized Discount	<u>(2,724)</u>	<u>(1,660)</u>
Total		<u>\$539,406</u>	<u>\$233,340</u>

- (a) This amount was redeemed in January 2004 using the proceeds from the variable interest Marshall County Installment Purchase Contract issued in December 2003. As a result of the early redemption, this amount is shown as due within one year in the debt maturity schedule.
- (b) A floating interest rate is determined daily. The rate on December 31, 2003 was 1.29%.
- (c) Due to FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003 (see Note 2). Prior to consolidation, payments for an operating lease were made to JMG based on JMG's cost of financing (both debt and equity). As a result of the consolidation, operating lease payments were not recognized and OPCo recorded JMG's debt along with other balance sheet and income statement items. See Note 15, "Leases," for further discussion of JMG.
- (d) A floating interest rate is determined weekly. The rate on December 31, 2003 was 1.13%.
- (e) A floating interest rate is determined weekly. The rate on December 31, 2003 was 1.20%

Under the terms of the installment purchase contracts, OPCo 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. Interest payments range from monthly to semi-annually.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6.75	2004 – July 1	\$100,000	\$100,000
7.00	2004 – July 1	75,000	75,000
6.73	2004 – November 1	48,000	48,000
6.24	2008 – December 4	37,225	37,225
7-3/8	2038 – June 30 (a)	140,000	140,000
5.50	2013 – February 15	250,000	-
4.85	2014 – January 15	225,000	-
6.60	2033 – February 15	250,000	-
6.375	2033 – July 15	225,000	-
	Unamortized Discount	(6,519)	(2,884)
Total		<u>\$1,343,706</u>	<u>\$397,341</u>

- (a) This note was redeemed on March 1, 2004 and has been classified for payment in 2004.

Notes Payable to parent company were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
4.336	2003 – May 15	\$-	\$60,000
6.501	2006 – May 15	-	240,000
Total		<u>\$-</u>	<u>\$300,000</u>

Notes Payable to third parties outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u> (in thousands)	<u>2002</u>
6.81	2008 – March 31 (a)	\$24,878 (d)	\$-
6.27	2009 – March 31 (b)	41,000 (d)	-
7.49	2009 – April 15	70,000 (d)	-
7.21	2009 – June 15 (c)	11,000 (d)	-
Total		<u>\$146,878</u>	<u>\$-</u>

- (a) The terms of this note require quarterly principal payments of \$5,853,659 per year through 2007 with the remaining \$1,463,415 due at maturity. These payments are reflected in the debt maturity schedule.
- (b) The terms of this note require semi-annual principal payments of \$3 million per year for the year 2004, \$6.5 million per year for the years 2005 and 2006, \$12 million per year for the years 2007 and 2008 with the remaining amount of \$1 million due at maturity. These payments are reflected in the debt maturity schedule.
- (c) The terms of this note require a principal payment of \$4.5 million in 2008 and the remaining amount of \$6.5 million due in the year of maturity which is reflected in the debt maturity schedule.
- (d) Due to FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003 (see Note 2). Prior to consolidation, payments for an operating lease were made to JMG based on JMG's cost of financing (both debt and equity). As a result of the consolidation, operating lease payments were not recognized and OPCo recorded JMG's debt along with other balance sheet and income statement items. See Note 15, "Leases," for further discussion of JMG.

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u> (in thousands)
2004	\$431,854
2005	12,354
2006	12,354
2007	17,853
2008	55,188
Later Years	<u>1,519,630</u>
Total Principal Amount	2,049,233
Unamortized Discount	<u>(9,293)</u>
Total	<u>\$2,039,940</u>

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to OPCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to OPCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Ohio Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Ohio Power Company Consolidated as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 Ohio Power Company Consolidated as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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 2 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
March 5, 2004

PUBLIC SERVICE COMPANY OF OKLAHOMA

**PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,102,822	\$793,647	\$957,000	\$956,398	\$749,390
Operating Expenses	<u>1,009,959</u>	<u>708,926</u>	<u>860,012</u>	<u>859,729</u>	<u>650,677</u>
Operating Income	92,863	84,721	96,988	96,669	98,713
Nonoperating Items, Net	5,812	(3,239)	20	8,974	946
Interest Charges	<u>44,784</u>	<u>40,422</u>	<u>39,249</u>	<u>38,980</u>	<u>38,151</u>
Net Income	53,891	41,060	57,759	66,663	61,508
Preferred Stock Dividend Requirements	213	213	213	212	212
Gain on Reacquired Preferred Stock	<u>-</u>	<u>1</u>	<u>-</u>	<u>-</u>	<u>-</u>
Earnings Applicable to Common Stock	<u><u>\$53,678</u></u>	<u><u>\$40,848</u></u>	<u><u>\$57,546</u></u>	<u><u>\$66,451</u></u>	<u><u>\$61,296</u></u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$2,806,396	\$2,759,504	\$2,695,099	\$2,604,670	\$2,459,705
Accumulated Depreciation and Amortization	<u>1,069,216</u>	<u>1,037,222</u>	<u>989,426</u>	<u>963,176</u>	<u>935,946</u>
Net Electric Utility Plant	<u><u>\$1,737,180</u></u>	<u><u>\$1,722,282</u></u>	<u><u>\$1,705,673</u></u>	<u><u>\$1,641,494</u></u>	<u><u>\$1,523,759</u></u>
TOTAL ASSETS	<u><u>\$1,970,032</u></u>	<u><u>\$1,979,323</u></u>	<u><u>\$1,943,928</u></u>	<u><u>\$2,325,500</u></u>	<u><u>\$1,703,155</u></u>
Common Stock and Paid-in Capital	\$387,246	\$337,246	\$337,246	\$337,246	\$337,246
Retained Earnings	139,604	116,474	142,994	137,688	139,237
Accumulated Other Comprehensive Income (Loss)	<u>(43,842)</u>	<u>(54,473)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u><u>\$483,008</u></u>	<u><u>\$399,247</u></u>	<u><u>\$480,240</u></u>	<u><u>\$474,934</u></u>	<u><u>\$476,483</u></u>
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u><u>\$5,267</u></u>	<u><u>\$5,267</u></u>	<u><u>\$5,267</u></u>	<u><u>\$5,267</u></u>	<u><u>\$5,270</u></u>
Trust Preferred Securities (a)	<u><u>\$-</u></u>	<u><u>\$75,000</u></u>	<u><u>\$75,000</u></u>	<u><u>\$75,000</u></u>	<u><u>\$75,000</u></u>
Long-term Debt (b)	<u><u>\$574,298</u></u>	<u><u>\$545,437</u></u>	<u><u>\$451,129</u></u>	<u><u>\$470,822</u></u>	<u><u>\$384,516</u></u>
Obligations Under Capital Leases (b)	<u><u>\$1,010</u></u>	<u><u>\$-</u></u>	<u><u>\$-</u></u>	<u><u>\$-</u></u>	<u><u>\$-</u></u>
TOTAL CAPITALIZATION AND LIABILITIES	<u><u>\$1,970,032</u></u>	<u><u>\$1,979,323</u></u>	<u><u>\$1,943,928</u></u>	<u><u>\$2,325,500</u></u>	<u><u>\$1,703,155</u></u>

(a) See Note 16 of the Notes to Respective Financial Statements.

(b) Including portion due within one year.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Public Service Company of Oklahoma (PSO) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 505,000 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. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Power pool members 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 revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

Net Income increased \$13 million for the year. The increase for the year was due mainly to higher retail base revenue and wholesale margins. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002 and changing natural gas prices; however, operating income was not significantly affected due to the functioning of the fuel adjustment clause in Oklahoma.

Operating Income

Operating Income increased \$8 million primarily due to:

- Increased wholesale margins of \$9 million due to an increase in our allocation percentage, in AEP's Power Pool, resulting from increased amounts of off-system sales.
- Increased retail base revenue of \$6 million (2%), resulting mainly from a 6% increase in KWH sold. Cooling degree-days decreased 3% while heating degree-days increased 1%.
- Decreased Other Operation expense of \$4 million which has several contributing factors including administrative and support expenses, outside services and related expenses.
- Decreased Taxes Other Than Income Taxes of \$2 million due primarily to decreased franchise taxes.

The increase in Operating Income was partially offset by:

- Increased Maintenance expense of \$5 million due mainly to increased plant maintenance and tree trimming.
- Increased Income Taxes of \$13 million due to an increase in pre-tax operating income and increases in tax return and tax accrual adjustments.

Other Impacts on Earnings

Nonoperating Income increased \$6 million primarily due to higher margins from risk management activities and gains on the disposition of excess land.

Nonoperating Expenses decreased \$6 million due to the 2002 write-down of certain non-utility investments.

Interest Charges increased \$4 million as a result of replacing floating rate short-term debt with long-term fixed rate unsecured debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$83,700	\$50,000	\$1,000	\$439,598	\$574,298
Advances from Affiliates	32,864	-	-	-	32,864
Unconditional Purchase Obligation (a)	181,379	175,082	139,916	377,568	873,945
Capital Lease Obligations	492	562	50	-	1,104
Noncancellable Operating Leases	<u>4,684</u>	<u>8,599</u>	<u>4,642</u>	<u>8,616</u>	<u>26,541</u>
Total	<u>\$303,119</u>	<u>\$234,243</u>	<u>\$145,608</u>	<u>\$825,782</u>	<u>\$1,508,752</u>

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

Significant Factors

See the “Registrants’ Combined Management’s Discussion and Analysis” section beginning on page M-1 for additional discussion of factors relevant to us.

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 “Qualitative And Quantitative Disclosures About Risk Management Activities” section. The following tables provide information about our risk management activities’ effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$3,545
(Gain) Loss from Contracts Realized/Settled During the Period (a)	1,308
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(69)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	-
Changes in Fair Value of Risk Management Contracts (e)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	<u>9,273</u>
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	<u>14,057</u>
Net Cash Flow Hedge Contracts (g)	<u>239</u>
Ending Balance December 31, 2003	<u><u>\$14,296</u></u>

- (a)“(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b)The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c)“Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d)See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e)“Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (f)“Change in Fair Value of Risk Management Contracts 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.
- (g) “Net Cash Flow Hedge Contracts (pre-tax)” are discussed below in Accumulated Other Comprehensive Income (Loss).

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actively Quoted – Exchange Exchange Traded Contracts	\$326	\$(136)	\$13	\$83	\$-	\$-	\$286
Prices Provided by Other External Sources – OTC Broker Quotes (a)	6,962	2,151	788	497	285	-	10,683
Prices Based on Models and Other Valuation Methods (b)	<u>(883)</u>	<u>676</u>	<u>155</u>	<u>325</u>	<u>680</u>	<u>2,135</u>	<u>3,088</u>
Total	<u>\$6,405</u>	<u>\$2,691</u>	<u>\$956</u>	<u>\$905</u>	<u>\$965</u>	<u>\$2,135</u>	<u>\$14,057</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$(42)
Changes in Fair Value (a)	18
Reclassifications from AOCI to Net Income (b)	<u>180</u>
Ending Balance December 31, 2003	<u>\$156</u>

- (a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
- (b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$724 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003				December 31, 2002			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$258	\$1,004	\$420	\$100	\$136	\$415	\$148	\$30

VaR Associated with Debt Outstanding

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 \$66 million and \$70 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,079,692	\$784,208	\$920,229
Sales to AEP Affiliates	<u>23,130</u>	<u>9,439</u>	<u>36,771</u>
TOTAL	<u>1,102,822</u>	<u>793,647</u>	<u>957,000</u>
OPERATING EXPENSES			
Fuel for Electric Generation	526,563	246,199	461,470
Purchased Electricity for Resale	35,685	47,507	24,187
Purchased Electricity from AEP Affiliates	109,639	89,454	43,758
Other Operation	129,246	133,538	137,678
Maintenance	53,076	48,060	46,188
Depreciation and Amortization	86,455	85,896	80,245
Taxes Other Than Income Taxes	32,287	34,077	31,973
Income Taxes	<u>37,008</u>	<u>24,195</u>	<u>34,513</u>
TOTAL	<u>1,009,959</u>	<u>708,926</u>	<u>860,012</u>
OPERATING INCOME	92,863	84,721	96,988
Nonoperating Income	8,026	1,920	2,112
Nonoperating Expense	1,385	6,971	1,740
Nonoperating Income Tax Expense (Credit)	829	(1,812)	352
Interest Charges	<u>44,784</u>	<u>40,422</u>	<u>39,249</u>
NET INCOME	53,891	41,060	57,759
Gain on Reacquired Preferred Stock	-	1	-
Preferred Stock Dividend Requirements	<u>213</u>	<u>213</u>	<u>213</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$53,678</u>	<u>\$40,848</u>	<u>\$57,546</u>

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$157,230	\$180,016	\$137,688	\$-	\$474,934
Common Stock Dividends Declared			(52,240)		(52,240)
Preferred Stock Dividends Declared			(213)		(213)
TOTAL					<u>422,481</u>
COMPREHENSIVE INCOME					
NET INCOME			57,759		<u>57,759</u>
TOTAL COMPREHENSIVE INCOME					<u>57,759</u>
DECEMBER 31, 2001	\$157,230	\$180,016	\$142,994	\$-	\$480,240
Gain on Reacquired Preferred Stock			1		1
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(213)		(213)
TOTAL					<u>412,660</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, (Loss)					
Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(42)	(42)
Minimum Pension Liability				(54,431)	(54,431)
NET INCOME			41,060		<u>41,060</u>
TOTAL COMPREHENSIVE INCOME					<u>(13,413)</u>
DECEMBER 31, 2002	\$157,230	\$180,016	\$116,474	\$(54,473)	\$399,247
Capital Contribution from Parent		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			(548)		(548)
TOTAL					<u>418,486</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income					
Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				198	198
Minimum Pension Liability				10,433	10,433
NET INCOME			53,891		<u>53,891</u>
TOTAL COMPREHENSIVE INCOME					<u>64,522</u>
DECEMBER 31, 2003	<u>\$157,230</u>	<u>\$230,016</u>	<u>\$139,604</u>	<u>\$(43,842)</u>	<u>\$483,008</u>

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	\$1,065,408	\$1,040,520
Transmission	451,292	432,846
Distribution	1,031,229	990,947
General	203,756	206,747
Construction Work in Progress	<u>54,711</u>	<u>88,444</u>
TOTAL	2,806,396	2,759,504
Accumulated Depreciation and Amortization	<u>1,069,216</u>	<u>1,037,222</u>
TOTAL - NET	<u>1,737,180</u>	<u>1,722,282</u>
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,631	4,833
Other Investments	<u>2,320</u>	<u>550</u>
TOTAL	<u>6,951</u>	<u>5,383</u>
CURRENT ASSETS		
Cash and Cash Equivalents	14,258	16,774
Accounts Receivable:		
Customers	28,515	30,130
Affiliated Companies	19,852	14,139
Miscellaneous	-	1,557
Allowance for Uncollectible Accounts	(37)	(84)
Fuel Inventory	18,331	19,973
Materials and Supplies	38,125	37,375
Regulatory Asset for Under-recovered Fuel Costs	24,170	76,470
Risk Management Assets	18,586	3,841
Margin Deposits	4,351	91
Prepayments and Other	<u>2,655</u>	<u>2,644</u>
TOTAL	<u>168,806</u>	<u>202,910</u>
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Required Debt	14,357	11,138
Other	14,342	15,012
Long-term Risk Management Assets	10,379	4,481
Deferred Charges	<u>18,017</u>	<u>18,117</u>
TOTAL	<u>57,095</u>	<u>48,748</u>
TOTAL ASSETS	<u>\$1,970,032</u>	<u>\$1,979,323</u>

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – \$15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	\$157,230	\$157,230
Paid-in Capital	230,016	180,016
Retained Earnings	139,604	116,474
Accumulated Other Comprehensive Income (Loss)	(43,842)	(54,473)
Total Common Shareholder's Equity	483,008	399,247
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,267	5,267
Total Shareholder's Equity	488,275	404,514
PSO – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	-	75,000
Long-term Debt	490,598	445,437
TOTAL	978,873	924,951
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	83,700	100,000
Advances from Affiliates	32,864	86,105
Accounts Payable:		
General	48,808	61,169
Affiliated Companies	57,206	78,076
Customer Deposits	26,547	21,789
Taxes Accrued	27,157	6,854
Interest Accrued	3,706	6,979
Risk Management Liabilities	11,067	3,260
Obligations Under Capital Leases	452	-
Other	35,234	24,957
TOTAL	326,741	389,189
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	335,434	341,396
Long-Term Risk Management Liabilities	3,602	1,581
Regulatory Liabilities:		
Asset Removal Costs	214,033	-
Deferred Investment Tax Credits	30,411	32,201
SFAS 109 Regulatory Liability, Net	24,937	27,893
Other	15,406	4,391
Obligations Under Capital Leases	558	-
Deferred Credits and Other	40,037	257,721
TOTAL	664,418	665,183
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	\$1,970,032	\$1,979,323

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$53,891	\$41,060	\$57,759
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Depreciation and Amortization	86,455	85,896	80,245
Deferred Income Taxes	(14,641)	75,659	(17,751)
Deferred Investment Tax Credits	(1,790)	(1,791)	(1,791)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(2,588)	(3,737)	21,405
Fuel, Materials and Supplies	892	996	(589)
Accounts Payable	(33,231)	25,629	(55,319)
Taxes Accrued	20,303	(11,296)	16,491
Fuel Recovery	52,300	(85,190)	51,987
Changes in Other Assets	(10,421)	1,796	(11,929)
Changes in Other Liabilities	14,987	(6,928)	9,351
Net Cash Flows From Operating Activities	<u>166,157</u>	<u>122,094</u>	<u>149,859</u>
INVESTING ACTIVITIES			
Construction Expenditures	(86,815)	(89,365)	(124,520)
Proceeds from Sale of Property and Other	2,862	963	(359)
Net Cash Flows Used For Investing Activities	<u>(83,953)</u>	<u>(88,402)</u>	<u>(124,879)</u>
FINANCING ACTIVITIES			
Capital Contributions from Parent	50,000	-	-
Issuance of Long-term Debt	148,734	187,850	-
Retirement of Long-term Debt	(200,000)	(106,000)	(20,000)
Change in Advances to/from Affiliates, Net	(53,241)	(36,982)	41,967
Dividends Paid on Common Stock	(30,000)	(67,368)	(52,240)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows Used For Financing Activities	<u>(84,720)</u>	<u>(22,713)</u>	<u>(30,486)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	(2,516)	10,979	(5,506)
Cash and Cash Equivalents at Beginning of Period	<u>16,774</u>	<u>5,795</u>	<u>11,301</u>
Cash and Cash Equivalents at End of Period	<u>\$14,258</u>	<u>\$16,774</u>	<u>\$5,795</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was \$44,703,000, \$38,620,000 and \$38,250,000 and for income taxes was \$36,470,000, (38,943,000) and \$38,653,000 in 2003, 2002 and 2001, respectively.

There was a non-cash distribution of \$548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
TOTAL COMMON SHAREHOLDER'S EQUITY	\$483,008	\$399,247

PREFERRED STOCK: Cumulative \$100 par value – authorized shares 700,000, redeemable at the option of PSO upon 30 days notice.

<u>Series</u>	<u>Call Price</u>	<u>Number of Shares Redeemed</u>			<u>Shares</u>		
	<u>December 31,</u> <u>2003</u>	<u>Year Ended December 31,</u> <u>2003</u>	<u>2002</u>	<u>2001</u>	<u>Outstanding</u> <u>December 31,</u> <u>2003</u>		
Not Subject to Mandatory Redemption:							
4.00%	\$105.75	2	6	-	44,598	4,460	4,460
4.24%	103.19	-	1	-	8,069	<u>807</u>	<u>807</u>
Total						5,267	5,267

TRUST PREFERRED SECURITIES:

PSO-Obligated, Mandatorily Redeemable Preferred

Securities of Subsidiary Trust Holding Solely

Junior Subordinated Debentures of PSO, 8.00%,

Due April 30, 2037 (a)

-	<u>75,000</u>
---	---------------

LONG-TERM DEBT (See Schedule of Long-term Debt):

First Mortgage Bonds	99,864	298,079
Installment Purchase Contracts	47,358	47,358
Note Payable to Trust (a)	77,320	-
Senior Unsecured Notes	349,756	200,000
Less Portion Due Within One Year	<u>(83,700)</u>	<u>(100,000)</u>
Long-term Debt Excluding Portion Due Within One Year	<u>490,598</u>	<u>445,437</u>

TOTAL CAPITALIZATION	<u>\$978,873</u>	<u>\$924,951</u>
-----------------------------	------------------	------------------

(a) See Note 16 for discussion of Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
6.25	2003 – April 1	\$-	\$ 35,000
7.25	2003 – July 1	-	65,000
7.38	2004 – December 1	50,000	50,000
6.50	2005 – June 1	50,000	50,000
7.38	2023 – April 1	-	100,000
	Unamortized Discount	<u>(136)</u>	<u>(1,921)</u>
Total		<u>\$99,864</u>	<u>\$298,079</u>

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains 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.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
			<u>(in thousands)</u>	
Oklahoma Environmental Finance Authority (OEFA):	5.90	2007 - December 1	\$1,000	\$1,000
Oklahoma Development Finance Authority (ODFA):	4.875	2014 - June 1 (a)	33,700	33,700
Red River Authority of Texas:	6.00	2020 – June 1	12,660	12,660
		Unamortized Discount	<u>(2)</u>	<u>(2)</u>
	Total		<u>\$47,358</u>	<u>\$47,358</u>

(a) These bonds will be remarketed on June 1, 2004.

Under the terms of the installment purchase contracts, PSO 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. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
4.85	2010 – September 15	\$150,000	\$-
6.00	2032 – December 31	200,000	200,000
	Unamortized Discount	<u>(244)</u>	<u>-</u>
Total		<u>\$349,756</u>	<u>\$200,000</u>

Notes Payable to Trust was outstanding as follows:

<u>% Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
8.00	2037 – April 30	(in thousands)	
		<u>\$77,320</u>	<u>\$-</u>

See Note 16 for discussion of Notes Payable to Trust.

At December 31, 2003, future annual long-term debt payments are as follows:

	<u>Amount</u>
	(in thousands)
2004	\$83,700
2005	50,000
2006	-
2007	1,000
2008	-
Later Years	<u>439,980</u>
Total Principal Amount	574,680
Unamortized Discount	<u>(382)</u>
Total	<u>\$574,298</u>

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to PSO's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Public Service Company of Oklahoma:

We have audited the accompanying balance sheets and statements of capitalization of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the related statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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 FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA**

	<u>2003</u>	<u>2002</u>	<u>2001</u> (in thousands)	<u>2000</u>	<u>1999</u>
<u>INCOME STATEMENTS DATA</u>					
Operating Revenues	\$1,146,842	\$1,084,720	\$1,101,326	\$1,118,274	\$971,527
Operating Expenses	<u>996,706</u>	<u>942,251</u>	<u>955,119</u>	<u>989,996</u>	<u>824,465</u>
Operating Income	150,136	142,469	146,207	128,278	147,062
Nonoperating Items, Net	4,767	(309)	741	3,851	(1,965)
Interest Charges	63,779	59,168	57,581	59,457	58,892
Minority Interest	<u>(1,500)</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Income Before Extraordinary Item And Cumulative Effect	89,624	82,992	89,367	72,672	86,205
Extraordinary Loss	-	-	-	-	(3,011)
Cumulative Effect of Accounting Changes	<u>8,517</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Net Income	98,141	82,992	89,367	72,672	83,194
Preferred Stock Dividend Requirements	<u>229</u>	<u>229</u>	<u>229</u>	<u>229</u>	<u>229</u>
Earnings Applicable to Common Stock	<u>\$97,912</u>	<u>\$82,763</u>	<u>\$89,138</u>	<u>\$72,443</u>	<u>\$82,965</u>
<u>BALANCE SHEETS DATA</u>					
Electric Utility Plant	\$3,799,460	\$3,596,174	\$3,460,764	\$3,319,024	\$3,231,431
Accumulated Depreciation and Amortization	<u>1,617,846</u>	<u>1,477,875</u>	<u>1,342,003</u>	<u>1,259,509</u>	<u>1,196,629</u>
Net Electric Utility Plant	<u>\$2,181,614</u>	<u>\$2,118,299</u>	<u>\$2,118,761</u>	<u>\$2,059,515</u>	<u>\$2,034,802</u>
TOTAL ASSETS	<u>\$2,581,963</u>	<u>\$2,428,138</u>	<u>\$2,509,291</u>	<u>\$2,855,885</u>	<u>\$2,294,375</u>
Common Stock and Paid-in Capital	\$380,663	\$380,663	\$380,663	\$380,663	\$380,663
Retained Earnings	359,907	334,789	308,915	293,989	283,546
Accumulated Other Comprehensive Income (Loss)	<u>(43,910)</u>	<u>(53,683)</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total Common Shareholder's Equity	<u>\$696,660</u>	<u>\$661,769</u>	<u>\$689,578</u>	<u>\$674,652</u>	<u>\$664,209</u>
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>\$4,700</u>	<u>\$4,701</u>	<u>\$4,701</u>	<u>\$4,701</u>	<u>\$4,703</u>
Trust Preferred Securities (a)	<u>\$-</u>	<u>\$110,000</u>	<u>\$110,000</u>	<u>\$110,000</u>	<u>\$110,000</u>
Long-term Debt (b)	<u>\$884,308</u>	<u>\$693,448</u>	<u>\$645,283</u>	<u>\$645,963</u>	<u>\$541,568</u>
Obligations Under Capital Leases (b)	<u>\$21,542</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$2,581,963</u>	<u>\$2,428,138</u>	<u>\$2,509,291</u>	<u>\$2,855,885</u>	<u>\$2,294,375</u>

(a) See Note 16 of the Notes to Respective Financial Statements.

(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Southwestern Electric Power Company (SWEPCo) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 439,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. 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. SWEPCo also sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

Power pool members 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 revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are 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 AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

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

Results of Operations

2003 Compared to 2002

During 2003, Net Income increased \$15 million primarily due to an \$8 million increase in Operating Income and the adoption of SFAS 143, which resulted in Cumulative Effect of Accounting Changes of \$9 million in the first quarter of 2003. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income increased by \$8 million primarily due to:

- A \$12 million increase in wholesale margins due to an increase in our allocation of overall AEP System sales percentages resulting from increased amounts of off-system sales.
- A \$12 million increase in retail base revenues due to increased customers and their average usage, offset in part by milder weather. Cooling and heating degree-days declined 6%.
- A \$7 million increase in income from risk management activities.
- A decrease of \$16 million in Other Operation expense primarily due to decreases in customer services, outside services and other administrative expenses.

The increase in Operating Income was partially offset by:

- A \$9 million decrease in wholesale base margins primarily due to decreased demand from wholesale customers.
- A \$4 million decrease in capacity revenues due to the elimination of the requirement under the Texas Restructuring legislation to sell capacity. See Note 6.
- A \$21 million increase in Income Taxes due to increases in pre-tax operating income, federal and state tax return and tax accrual adjustments and changes to certain book/tax timing differences accounted for on a flow-through basis.

Other Impacts on Earnings

Nonoperating Income Tax Credit increased by \$5 million due to changes in certain book/tax timing differences accounted for on a flow-through basis, changes in consolidated tax savings and tax return and tax accrual adjustments.

Interest Charges increased \$5 million primarily due to higher levels of outstanding debt, consolidation of Sabine Mining Company and in financing activity at Dolet Hills.

Minority Interest expense of \$2 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to the implementation of FIN 46. See Notes 2 and 8 for additional discussion.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2002 Compared to 2001

During 2002, Net Income decreased \$6 million primarily resulting from reduced margins from risk management activities. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income decreased by \$4 million primarily due to:

- A \$4 million decrease in retail base revenues mainly due to decreased KWH sales of 6% resulting from the loss of a large industrial customer in 2002.
- A \$15 million decrease in income from risk management activities.
- An increase of \$18 million in Other Operation expense primarily due to the acquisition of Dolet Hills Lignite Company.
- A \$3 million increase in Depreciation and Amortization due primarily to the Dolet Hills acquisition.

The decrease in Operating Income was partially offset by:

- An increase of \$13 million in other revenue primarily from the Dolet Hills Acquisition.
- An increase of \$7 million in capacity revenues, due to the requirement under the Texas Restructuring legislation to sell capacity.
- An \$8 million decrease in Maintenance expense due to less storm damage and reduced tree trimming expense in 2002.
- A decrease in Income Taxes of \$8 million due to a decrease in pre-tax income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Cash and cash equivalents at beginning of period	<u>\$2,069</u>	<u>\$5,415</u>	<u>\$1,907</u>
Cash flows from (used for):			
Operating activities	248,094	210,563	169,610
Investing activities	(110,849)	(110,641)	(197,852)
Financing activities	<u>(127,590)</u>	<u>(103,268)</u>	<u>31,750</u>
Net increase (decrease) in cash and cash equivalents	<u>9,655</u>	<u>(3,346)</u>	<u>3,508</u>
Cash and cash equivalents at end of period	<u>\$11,724</u>	<u>\$2,069</u>	<u>\$5,415</u>

Operating Activities

Cash flows from operating activities were \$248 million during 2003 primarily due to net income, Accounts Receivables, Accounts Payable and Accrued Taxes.

Investing Activities

Cash spent on investing activities during 2003 were comparable to 2002. In 2003, construction expenditures were primarily related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities increased by \$24 million during 2003 in comparison to 2002. During 2003 we paid \$16 million more in common stock dividends than in 2002. 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 debt due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued \$44 million of notes due in 2011 at a coupon of 4.47%. The loan was used primarily to reduce a note to us with an interest rate of 8.06%. During the fourth quarter of 2003, we had an early redemption of \$45 million of first mortgage bonds due in 2023.

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, 2003:

<u>Contractual Cash Obligations</u>	Payments Due by Period				<u>Total</u>
	<u>Less Than 1 year</u>	<u>2-3 years</u>	<u>4-5 years</u>	<u>After 5 years</u>	
Long-term Debt	\$142,714	\$226,628	\$123,263	\$391,703	\$884,308
Unconditional Purchase Obligations (a)	185,425	329,513	85,800	171,601	772,339
Capital Lease Obligations	4,737	9,174	8,799	4,380	27,090
Noncancellable Operating Leases	<u>5,522</u>	<u>12,864</u>	<u>14,669</u>	<u>17,849</u>	<u>50,904</u>
Total	<u>\$338,398</u>	<u>\$578,179</u>	<u>\$232,531</u>	<u>\$585,533</u>	<u>\$1,734,641</u>

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, we have agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, our total future maximum payment exposure is approximately \$58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, we have agreed to provide guarantees of mine reclamation in the amount of approximately \$85 million. Since we use self-bonding, the guarantee provides for us 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, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately \$36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, we consolidated Sabine due to the application of FIN 46 (see Note 2). 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

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

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 "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets Year Ended December 31, 2003 (in thousands)

Domestic Power

Beginning Balance December 31, 2002	\$4,050
(Gain) Loss from Contracts Realized/Settled During the Period (a)	820
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(32)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	151
Changes in Fair Value of Risk Management Contracts (e)	4,002
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	<u>7,615</u>
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	16,606
Net Cash Flow Hedge Contracts (g)	<u>(741)</u>
Ending Balance December 31, 2003	<u>\$15,865</u>

- (a) “(Gain) Loss from Contracts Realized/Settled During the Period” includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
- (b) The “Fair Value of New Contracts When Entered Into During the Period” represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
- (c) “Net Option Premiums Paid/(Received)” reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
- (d) See Note 2 “New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes.”
- (e) “Changes in Fair Value of Risk Management Contracts” represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (f) “Change in Fair Value of Risk Management Contracts 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.
- (g) “Net Cash Flow Hedge Contracts (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of 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, giving 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, 2003**

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>After 2008</u>	<u>Total (c)</u>
	(in thousands)						
Prices Actively Quoted – Exchange Traded Contracts	\$384	\$(160)	\$15	\$98	\$-	\$-	\$337
Prices Provided by Other External Sources – OTC Broker Quotes (a)	8,198	2,533	928	585	336	-	12,580
Prices Based on Models and Other Valuation Methods (b)	<u>(970)</u>	<u>776</u>	<u>183</u>	<u>383</u>	<u>800</u>	<u>2,517</u>	<u>3,689</u>
Total	<u>\$7,612</u>	<u>\$3,149</u>	<u>\$1,126</u>	<u>\$1,066</u>	<u>\$1,136</u>	<u>\$2,517</u>	<u>\$16,606</u>

- (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 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.
- (c) Amounts exclude Cash Flow Hedges.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

**Total Accumulated Other Comprehensive Income (Loss) Activity
Years Ended December 31, 2003**

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	\$(48)
Changes in Fair Value (a)	21
Reclassifications from AOCI to Net Income (b)	<u>211</u>
Ending Balance December 31, 2003	<u>\$184</u>

- (a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item’s affecting net income. Amounts are reported net of related income taxes.
- (b) “Reclassifications from AOCI to Net Income” represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an \$853 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

<u>December 31, 2003</u>				<u>December 31, 2002</u>			
(in thousands)				(in thousands)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$304	\$1,182	\$495	\$118	\$155	\$474	\$170	\$34

VaR Associated with Debt Outstanding

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 \$57 million and \$70 million at December 31, 2003 and 2002, 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 operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	\$1,077,988	\$1,012,421	\$1,022,089
Sales to AEP Affiliates	<u>68,854</u>	<u>72,299</u>	<u>79,237</u>
TOTAL	<u>1,146,842</u>	<u>1,084,720</u>	<u>1,101,326</u>
OPERATING EXPENSES			
Fuel for Electric Generation	441,445	388,334	457,613
Purchased Electricity for Resale	34,850	44,119	18,164
Purchased Electricity from AEP Affiliates	47,914	42,022	15,858
Other Operation	173,349	189,024	171,314
Maintenance	70,443	66,855	74,677
Depreciation and Amortization	121,072	122,969	119,543
Taxes Other Than Income Taxes	53,165	55,232	55,834
Income Taxes	<u>54,468</u>	<u>33,696</u>	<u>42,116</u>
TOTAL	<u>996,706</u>	<u>942,251</u>	<u>955,119</u>
OPERATING INCOME	150,136	142,469	146,207
Nonoperating Income	3,978	3,260	4,512
Nonoperating Expenses	2,607	1,797	3,229
Nonoperating Income Tax Expense (Credit)	(3,396)	1,772	542
Interest Charges	63,779	59,168	57,581
Minority Interest	<u>(1,500)</u>	<u>-</u>	<u>-</u>
Income Before Cumulative Effect of Accounting Changes	89,624	82,992	89,367
Cumulative Effect of Accounting Changes (Net of Tax)	<u>8,517</u>	<u>-</u>	<u>-</u>
NET INCOME	98,141	82,992	89,367
Preferred Stock Dividend Requirements	<u>229</u>	<u>229</u>	<u>229</u>
EARNINGS APPLICABLE TO COMMON STOCK	<u>\$97,912</u>	<u>\$82,763</u>	<u>\$89,138</u>

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)**

	<u>Common Stock</u>	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total</u>
DECEMBER 31, 2000	\$135,660	\$245,003	\$293,989	\$-	\$674,652
Common Stock Dividends			(74,212)		(74,212)
Preferred Stock Dividends			(229)		(229)
TOTAL					<u>600,211</u>
COMPREHENSIVE INCOME					
NET INCOME			89,367		<u>89,367</u>
TOTAL COMPREHENSIVE INCOME					<u>89,367</u>
DECEMBER 31, 2001	\$135,660	\$245,003	\$308,915	\$-	\$689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(229)		(229)
TOTAL					<u>632,460</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				(48)	(48)
Minimum Pension Liability				(53,635)	(53,635)
NET INCOME			82,992		<u>82,992</u>
TOTAL COMPREHENSIVE INCOME					<u>29,309</u>
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					<u>588,746</u>
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				232	232
Minimum Pension Liability				9,541	9,541
NET INCOME			98,141		<u>98,141</u>
TOTAL COMPREHENSIVE INCOME					<u>107,914</u>
DECEMBER 31, 2003	<u>\$135,660</u>	<u>\$245,003</u>	<u>\$359,907</u>	<u>\$(43,910)</u>	<u>\$696,660</u>

See Notes to Respective Financial Statements beginning on page L-1.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS**

ASSETS

December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
<u>ELECTRIC UTILITY PLANT</u>		
Production	\$1,622,498	\$1,503,722
Transmission	615,158	575,003
Distribution	1,078,368	1,063,564
General	423,427	378,130
Construction Work in Progress	60,009	75,755
TOTAL	<u>3,799,460</u>	<u>3,596,174</u>
Accumulated Depreciation and Amortization	<u>1,617,846</u>	<u>1,477,875</u>
TOTAL - NET	<u>2,181,614</u>	<u>2,118,299</u>
<u>OTHER PROPERTY AND INVESTMENTS</u>		
Non-Utility Property, Net	3,808	4,203
Other Investments	<u>4,710</u>	<u>1,775</u>
TOTAL	<u>8,518</u>	<u>5,978</u>
<u>CURRENT ASSETS</u>		
Cash and Cash Equivalents	11,724	2,069
Advances to Affiliates	66,476	-
Accounts Receivable:		
Customers	41,474	61,478
Affiliated Companies	10,394	19,253
Miscellaneous	4,682	881
Allowance for Uncollectible Accounts	(2,093)	(2,128)
Fuel Inventory	63,881	61,741
Materials and Supplies	33,775	33,539
Regulatory Asset for Under-recovered Fuel Costs	11,394	2,865
Risk Management Assets	19,715	4,388
Margin Deposits	5,123	105
Prepayments and Other	<u>19,078</u>	<u>17,746</u>
TOTAL	<u>285,623</u>	<u>201,937</u>
<u>DEFERRED DEBITS AND OTHER ASSETS</u>		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,235	19,855
Unamortized Loss on Required Debt	19,331	17,031
Other	15,859	12,347
Long-term Risk Management Assets	12,178	5,119
Deferred Charges	<u>55,605</u>	<u>47,572</u>
TOTAL	<u>106,208</u>	<u>101,924</u>
TOTAL ASSETS	<u>\$2,581,963</u>	<u>\$2,428,138</u>

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	<u>2003</u>	<u>2002</u>
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – \$18 Par Value:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	\$135,660	\$135,660
Paid-in Capital	245,003	245,003
Retained Earnings	359,907	334,789
Accumulated Other Comprehensive Income (Loss)	<u>(43,910)</u>	<u>(53,683)</u>
Total Common Shareholder's Equity	696,660	661,769
Cumulative Preferred Stock Not Subject to Mandatory Redemption	<u>4,700</u>	<u>4,701</u>
Total Shareholder's Equity	701,360	666,470
SWEPCo – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo	-	110,000
Long-term Debt	<u>741,594</u>	<u>637,853</u>
TOTAL	<u>1,442,954</u>	<u>1,414,323</u>
Minority Interest	<u>1,367</u>	<u>-</u>
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	142,714	55,595
Advances from Affiliates	-	23,239
Accounts Payable:		
General	37,646	62,139
Affiliated Companies	35,138	58,773
Customer Deposits	24,260	20,110
Taxes Accrued	28,691	19,081
Interest Accrued	16,852	17,051
Risk Management Liabilities	11,361	3,724
Obligations Under Capital Leases	3,159	-
Regulatory Liability for Over-recovered Fuel	4,178	17,226
Other	<u>53,753</u>	<u>34,565</u>
TOTAL	<u>357,752</u>	<u>311,503</u>
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	349,064	341,064
Long-term Risk Management Liabilities	4,667	1,806
Reclamation Reserve	16,512	13,826
Regulatory Liabilities:		
Asset Removal Costs	236,409	-
Deferred Investment Tax Credits	39,864	44,190
Excess Earnings	2,600	3,700
Other	18,779	3,394
Asset Retirement Obligations	8,429	-
Obligations Under Capital Leases	18,383	-
Deferred Credits and Other	<u>85,183</u>	<u>294,332</u>
TOTAL	<u>779,890</u>	<u>702,312</u>
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$2,581,963</u>	<u>\$2,428,138</u>

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
OPERATING ACTIVITIES			
Net Income	\$98,141	\$82,992	\$89,367
Adjustments to Reconcile Net Income to Net Cash Flows			
From Operating Activities:			
Depreciation and Amortization	121,072	122,969	119,543
Deferred Income Taxes	9,942	(3,134)	(31,396)
Deferred Investment Tax Credits	(4,326)	(4,524)	(4,453)
Cumulative Effect of Accounting Changes	(8,517)	-	-
Mark-to-Market of Risk Management Contracts	(12,403)	(1,151)	(10,695)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	27,527	(24,371)	(11,447)
Fuel, Materials and Supplies	4,165	(10,541)	(19,578)
Accounts Payable	(51,687)	11,633	(34,489)
Taxes Accrued	8,446	(17,441)	25,298
Fuel Recovery	(21,577)	17,713	34,423
Change in Other Assets	16,268	24,257	1,323
Change in Other Liabilities	61,043	12,161	11,714
Net Cash Flows From Operating Activities	<u>248,094</u>	<u>210,563</u>	<u>169,610</u>
INVESTING ACTIVITIES			
Construction Expenditures	(121,124)	(111,775)	(111,725)
Investment in Mining Operations	-	-	(85,716)
Proceeds from Sale of Assets and Other	10,275	1,134	(411)
Net Cash Flows Used For Investing Activities	<u>(110,849)</u>	<u>(110,641)</u>	<u>(197,852)</u>
FINANCING ACTIVITIES			
Issuance of Long-term Debt	254,630	198,573	-
Retirement of Long-term Debt	(219,482)	(150,595)	(595)
Change in Advances to/from Affiliates, Net	(89,715)	(94,128)	106,786
Dividends Paid on Common Stock	(72,794)	(56,889)	(74,212)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows From (Used For) Financing Activities	<u>(127,590)</u>	<u>(103,268)</u>	<u>31,750</u>
Net Increase (Decrease) in Cash and Cash Equivalents	9,655	(3,346)	3,508
Cash and Cash Equivalents at Beginning of Period	<u>2,069</u>	<u>5,415</u>	<u>1,907</u>
Cash and Cash Equivalents at End of Period	<u>\$11,724</u>	<u>\$2,069</u>	<u>\$5,415</u>

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was \$57,775,000, \$49,008,000 and \$51,126,000 and for income taxes was \$33,616,000, \$60,451,000 and \$49,901,000 in 2003, 2002 and 2001, respectively.

Noncash activity in 2003 included an increase in assets and liabilities of \$78 million resulting from the consolidation of Sabine Mining Company (see Note 2).

See Notes to Respective Financial Statements beginning on page L-1.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002**

						<u>2003</u>	<u>2002</u>
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						<u>\$696,660</u>	<u>\$661,769</u>
PREFERRED STOCK: \$100 par value – authorized shares 1,860,000							
<u>Series</u>	<u>Call Price December 31, 2003</u>	<u>Number of Shares Redeemed Year Ended December 31,</u>			<u>Shares Outstanding December 31, 2003</u>		
		<u>2003</u>	<u>2002</u>	<u>2001</u>			
Not Subject to Mandatory Redemption:							
4.28%	\$103.90	-	-	-	7,386	740	740
4.65%	\$102.75	-	-	-	1,907	190	190
5.00%	\$109.00	12	-	-	37,703	<u>3,770</u>	<u>3,771</u>
Total Preferred Stock						<u>4,700</u>	<u>4,701</u>
TRUST PREFERRED SECURITIES:							
SWEPCo-Obligated, Mandatorily Redeemable Preferred							
Securities of Subsidiary Trust Holding Solely							
Junior Subordinated Debentures of SWEPCo, 7.875%,							
due April 30, 2037 (a)							
						<u>-</u>	<u>110,000</u>
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						215,712	315,420
Installment Purchase Contracts						178,531	179,183
Senior Unsecured Notes						299,216	198,845
Notes Payable to Trust (a)						113,009	-
Notes Payable						77,840	-
Less Portion Due Within One Year						<u>(142,714)</u>	<u>(55,595)</u>
Long-term Debt Excluding Portion Due Within One Year						<u>741,594</u>	<u>637,853</u>
TOTAL CAPITALIZATION						<u>\$1,442,954</u>	<u>\$1,414,323</u>

(a) See Note 16 for Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

		<u>2003</u>	<u>2002</u>
<u>% Rate</u>	<u>Due</u>	<u>(in thousands)</u>	
6-5/8	2003 – February 1	\$-	\$55,000
7-3/4	2004 – June 1	40,000	40,000
6.20	2006 – November 1	5,360	5,505
6.20	2006 – November 1	1,000	1,000
7.00	2007 – September 1	90,000	90,000
7-1/4	2023 – July 1	-	45,000
6-7/8	2025 – October 1 (a)	80,000	80,000
Unamortized Discount		<u>(648)</u>	<u>(1,085)</u>
Total		<u>\$215,712</u>	<u>\$315,420</u>

(a) This bond was redeemed on March 1, 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

		<u>2003</u>	<u>2002</u>
<u>% Rate</u>	<u>Due</u>	<u>(in thousands)</u>	
Desoto County:			
7.60	2019 – January 1	\$53,500	\$53,500
Sabine River Authority of Texas:			
6.10	2018 – April 1	81,700	81,700
Titus County:			
6.90	2004 – November 1	12,290	12,290
6.00	2008 – January 1	12,170	12,620
8.20	2011 – August 1	17,125	17,125
Unamortized Premium		<u>1,746</u>	<u>1,948</u>
Total		<u>\$178,531</u>	<u>\$179,183</u>

Under the terms of the installment purchase contracts, SWEPCo 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.

Senior Unsecured Notes outstanding were as follows:

<u>%Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
4.50	2005 – July 1	\$200,000	\$200,000
5.38	2015 – April 15	100,000	-
	Unamortized Discount	<u>(784)</u>	<u>(1,155)</u>
Total		<u>\$299,216</u>	<u>\$198,845</u>

Notes Payable to Trust was outstanding as follows:

<u>%Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
5.25% (a)	2043 – October 1	\$113,403	\$-
	Unamortized Discount	<u>(394)</u>	<u>-</u>
Total		<u>\$113,009</u>	<u>\$-</u>

(a) The 5.25% interest rate is thru September 10, 2008 after which they become floating rate bonds if the notes are not remarketed.

See Note 16 for discussion of Notes Payable to Trust.

Notes Payable outstanding were as follows:

<u>%Rate</u>	<u>Due</u>	<u>2003</u>	<u>2002</u>
		<u>(in thousands)</u>	
Sabine Mining Company (a):			
6.36	2007 – February 22	\$4,000	\$-
(b)	2008 – June 30	13,500	-
7.03	2012 – February 22	20,000	-
Dolet Hills Lignite Company:			
4.47	2011 – May 16	<u>40,340</u>	<u>-</u>
Total		<u>\$77,840</u>	<u>\$-</u>

(a) Sabine Mining Company was consolidated during the third quarter of 2003 due to the implementation of FIN 46.

(b) A floating interest rate is determined quarterly. The rate on December 31, 2003 was 1.54%.

At December 31, 2003 future annual long-term debt payments are as follows:

	<u>Amount</u>
	<u>(in thousands)</u>
2004	\$142,714
2005	210,424
2006	16,204
2007	104,862
2008	18,401
Later Years	<u>391,783</u>
Total Principal Amount	884,388
Unamortized Discount	<u>(80)</u>
Total	<u>\$884,308</u>

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS**

The notes to SWEPCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

	<u>Footnote Reference</u>
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Goodwill and Other Intangible Assets	Note 3
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 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 2 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
March 5, 2004

NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to respective financial statements that follow are a combined presentation for AEP's subsidiary registrants. 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.	Sustained Earnings Improvement Initiative	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	APCo, CSPCo, I&M, KPCo, OPCo, SWEPCo, 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
20.	Subsequent Events (Unaudited)	TCC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEP's ten domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act 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, AEP's registrant subsidiaries engage in wholesale marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates.

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. 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 Nonoperating Income.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the 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. 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. The following 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, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

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

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other 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 deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

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 non-regulated 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 not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, through the use of composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the year 2003:

	<u>Nuclear</u>	<u>Steam</u>	<u>Hydro</u>	<u>Transmission</u>	<u>Distribution</u>	<u>General</u>
AEGCo	- %	3.5%	- %	- %	- %	16.7%
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the years 2002 and 2001 were as follows:

	<u>Nuclear</u>	<u>Steam</u>	<u>Hydro</u>	<u>Transmission</u>	<u>Distribution</u>	<u>General</u>
AEGCo	- %	3.5%	- %	- %	- %	2.8%
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

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 \$0.41 per ton in 2003, 2002 and 2001 and related to OPCo were \$3.46 per ton in 2001. In 2001, OPCo sold coal mines in Ohio and West Virginia.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value 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.

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and its registrant subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for 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. 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, allowing the receivables to be taken off of the company's balance sheet. See Note 16 for further details.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. For the Texas companies, TCC & TNC, their deferred fuel balances will be included in their 2004 True Up Proceeding (see Note 6 "Customer Choice and Industry Restructuring"). See Note 5 "Effects of Regulation" for the amount of deferred fuel costs by registrant subsidiary.

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 timely reflected in rates through the fuel cost adjustment clauses in place in those states. 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. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), 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. In accordance with SFAS 71, 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 through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in 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 mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into 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.

After January 1, 2003, registrant subsidiaries use mark-to-market 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. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

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

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement 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 and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 13).

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially

electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statement on a net basis.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, registrant subsidiaries enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2003 or 2002.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with regulated revenues, 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 commencement of an outage and ending with the beginning of the next outage.

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 maintenance costs with their recovery in cost-based regulated revenues.

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 cost and tax basis of assets and liabilities which will result in a future tax consequence.

The flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

Registrant subsidiaries, as agents for some state and local governments collect from customers certain excise taxes levied by those state or local governments on our customers. We 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 plant are generally 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. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Nonoperating Income or Nonoperating Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

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 amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

In the first quarter of fiscal 2002, AEP's registrant subsidiaries adopted SFAS No. 142, "Goodwill and Other Intangible Assets" which revises the accounting for purchased goodwill and other intangible assets. Under SFAS No. 142, purchased goodwill and intangible assets with indefinite lives are no longer amortized, but instead tested for impairment at least annually. Intangible assets with finite lives, requires that they be amortized over their respective estimated lives to the estimated residual values. The AEP registrant subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2003 and 2002. SWEPCo is the only AEP registrant with an intangible asset with a finite life on its books. See Note 3 for further information about SWEPCo's intangible asset.

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 fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) 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

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP subsidiaries, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-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 the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. 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.

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 (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 sheet in the equity section. Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries as of December 31, 2003 and 2002 is shown in the following table.

<u>Components</u>	<u>December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in thousands)	
Cash Flow Hedges:		
APCo	\$(1,569)	\$(1,920)
CSPCo	202	(267)
I&M	222	(286)
KPCo	420	322
OPCo	(103)	(738)
PSO	156	(42)
SWEPCo	184	(48)
TCC	(1,828)	(36)
TNC	(601)	(15)
Minimum Pension Liability:		
APCo	\$(50,519)	\$(70,162)
CSPCo	(46,529)	(59,090)
I&M	(25,328)	(40,201)
KPCo	(6,633)	(9,773)
OPCo	(48,704)	(72,148)
PSO	(43,998)	(54,431)
SWEPCo	(44,094)	(53,635)
TCC	(60,044)	(73,124)
TNC	(26,117)	(30,748)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are wholly-owned subsidiaries of AEP and are not required to report EPS.

Supplementary Information

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2003, 2002 and 2001 were:

	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>OPCo</u>
	(in thousands)			
Year Ended December 31, 2003	\$55,219	\$15,259	\$25,659	\$50,995
Year Ended December 31, 2002	53,386	14,885	23,282	50,135
Year Ended December 31, 2001	45,542	12,626	20,723	47,757

Reclassification

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

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) “Employers’ Disclosure about Pensions and Other Postretirement Benefits”

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC’s 2004 quarterly financial statements.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end. See Note 11 for these additional 2003 disclosures.

SFAS 142 “Goodwill and Other Intangible Assets”

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 “Accounting for Asset Retirement Obligations”

We implemented SFAS 143, “Accounting for Asset Retirement Obligations,” effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for I&M’s Cook Plant and TCC’s partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143, as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect for the non-regulated operations. See the table later in this section for a summary by registrant subsidiary of the cumulative effect of changes in accounting principles for the year ended December 31, 2003.

Certain of AEP’s registrant subsidiaries have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that such registrant subsidiaries have now been deregulated, the registrant subsidiaries reversed the balance of such removal costs which resulted in a net favorable cumulative effect in 2003. The following is a summary by registrant subsidiary of the removal costs reclassified from Accumulated Depreciation and Amortization to Asset Removal Costs in 2003 and to Deferred Credits and Other in 2002 (Other on AEGCo’s 2002 Balance Sheet):

December 31, 2003 December 31, 2002

	(in millions)	
AEGCo	\$ 27.8	\$ 28.0
APCo	92.5	94.6
CSPCo	99.1	96.0
I&M	263.0	250.5
KPCo	26.1	23.7
OPCo	101.2	97.0
PSO	214.0	202.6
SWEPCo	236.4	219.5
TCC (a)	104.8	97.5
TNC	76.7	75.0

(a) Includes \$9 million classified as Liabilities Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets as of December 31, 2003 and 2002.

The following is a summary by registrant subsidiary of the cumulative effect of change in accounting principle, as a result of SFAS 143, for the year ended December 31, 2003:

	<u>Pre-tax Income (Loss)</u>		<u>After-tax Income (Loss)</u>	
	(in millions)			
	<u>Ash Ponds</u>	<u>Reversal of Cost of Removal</u>	<u>Ash Ponds</u>	<u>Reversal of Cost of Removal</u>
AEGCo	\$ -	\$ -	\$ -	\$ -
APCo	(18.2)	146.5	(11.4)	91.7
CSPCo	(7.8)	56.8	(4.7)	33.9
I&M	-	-	-	-
KPCo	-	-	-	-
OPCo	(36.8)	250.4	(21.9)	149.3
PSO	-	-	-	-
SWEPCo	-	13.0	-	8.4
TCC	-	-	-	-
TNC	-	4.7	-	3.1

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution 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.

The following is a reconciliation of beginning and ending aggregate carrying amounts of asset retirement obligations by registrant subsidiary following the adoption of SFAS 143:

	<u>Balance At January 1, 2003</u>		<u>Liabilities Incurred</u>	<u>Balance at December 31, 2003</u>
	(in millions)			
AEGCo (a)	\$1.1	\$-	\$-	\$1.1
APCo (a)	20.1	1.6	-	21.7
CSPCo (a)	8.1	0.6	-	8.7
I&M (b)	516.1	37.1	-	553.2
OPCo (a)	39.5	3.2	-	42.7
SWEPCo (d)	-	0.3	8.1	8.4
TCC (c)	203.2	15.6	-	218.8

- (a) Consists of asset retirement obligations related to ash ponds.
- (b) Consists of asset retirement obligations related to ash ponds (\$1.1 million at December 31, 2003) and nuclear decommissioning costs for the Cook Plant (\$552.1 million at December 31, 2003).
- (c) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale – Texas Generation Plants on TCC’s Consolidated Balance Sheets.
- (d) Consists of asset retirement obligations related to Sabine Mining which is now being consolidated under FIN 46 (see FIN 46 “Consolidation of Variable Interest Entities” later in this note).

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled \$845 million (\$720 million for I&M and \$125 million for TCC) and \$716 million (\$618 million for I&M and \$98 million for TCC), respectively, recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M’s Consolidated Balance Sheets and in Assets Held for Sale-Texas Generation Plants on TCC’s Consolidated Balance Sheets.

Pro forma net income has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income not materially different from the actual amounts reported for those periods.

The following is a summary by registrant subsidiary of the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted as of the beginning of each period presented:

	December 31,		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
	(in millions)		
AEGCo	\$ 1.1	\$ 1.0	\$0.9
APCo	20.1	18.7	17.3
CSPCo	8.1	7.5	6.9
I&M	516.1	481.4	449.1
KPCo	-	-	-
OPCo	39.5	36.5	33.8
PSO	-	-	-
SWEPCo	-	-	-
TCC	203.2	188.8	175.4
TNC	-	-	-

SFAS 144 “Accounting for the Impairment or Disposal of Long-lived Assets”

In August 2001, the FASB issued SFAS 144, “Accounting for the Impairment or Disposal of Long-lived Assets” which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, “Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of.” All of the registrant subsidiaries adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections”

In April 2002, the FASB issued SFAS 145, “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections” (SFAS 145). SFAS 145 rescinds SFAS 4, “Reporting Gains and Losses from Extinguishment of Debt,” effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, TCC reclassified Extraordinary Losses (Net of Tax) on its reacquired debt of \$2 million for 2001 to Nonoperating Expenses and Nonoperating Income Tax Expense.

SFAS 146 “Accounting for Costs Associated with Exit or Disposal Activities”

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity’s commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. The registrant subsidiaries adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 “Amendment of Statement 133 on Derivative Instruments and Hedging Activities”

On April 30, 2003, the FASB issued Statement No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities” (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify as “normal purchase/normal sale.” SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, registrant subsidiaries implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 “Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity”

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB’s project to eliminate from the balance sheet the “mezzanine” presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of “dividends” and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks Subject to Mandatory Redemption as Liability for Cumulative Preferred Stock Subject to Mandatory Redemption. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Charges. In accordance with SFAS 150, dividends from prior periods remain classified as Preferred Stock Dividends.

FIN 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others”

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize a liability related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003) “Consolidation of Variable Interest Entities” and FIN 46 “Consolidation of Variable Interest Entities”

We implemented FIN 46, “Consolidation of Variable Interest Entities,” effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, “Consolidated Financial Statements,” to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the \$321 million net amount (\$75 million PSO, \$110 million SWEPCo and \$136 million TCC), reported as “Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries” at December 31, 2002, \$331 million (\$77

million PSO, \$113 million SWEPCo and \$141 million TCC) is reported as a component of Long-term Debt and \$10 million (\$2 million PSO, \$3 million SWEPCo and \$5 million TCC) is reported in Other Investments within Other Property and Investments at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine (\$78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG (\$469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 15 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and the Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. Registrant subsidiaries have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into 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 "Cumulative Effect of Accounting Change" for a summary by registrant subsidiary).

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, the registrant subsidiaries recorded and reported upon settlement, sales under forward risk management contracts as revenues. Registrant subsidiaries also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, the registrant subsidiaries reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for

any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether AEP's plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to the accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, any potential effects of the Act were deferred until authoritative guidance on the accounting for the federal subsidy is issued. Measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Certain registrant subsidiaries have recorded after tax charges against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003. This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, certain of the registrant subsidiaries recorded in after-tax income a cumulative effect of accounting change for Asset Retirement Obligations.

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	<u>SFAS 143 Cumulative Effect</u>		<u>EITF 02-3 Cumulative Effect</u>	
	<u>Pre-tax Income (Loss)</u>	<u>After-tax Income (Loss)</u>	<u>Pre-tax Income (Loss)</u>	<u>After-tax Income (Loss)</u>
	(in millions)		(in millions)	
APCo	\$128.3	\$ 80.3	\$ (4.7)	\$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

EXTRAORDINARY ITEMS

In 2003 an extraordinary item of \$177,000, net of tax of \$95,000, 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. AEP's registrant subsidiaries had no extraordinary items in 2002. In 2001 an extraordinary item was recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of \$48 million (net of tax of \$20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the AEP registrant subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is \$21.7 million at December 31, 2003 and \$24.7 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life are:

	<u>Amortization Life</u> (in years)	<u>December 31, 2003</u>		<u>December 31, 2002</u>	
		<u>Gross Carrying Amount</u> (in millions)	<u>Accumulated Amortization</u>	<u>Gross Carrying Amount</u> (in millions)	<u>Accumulated Amortization</u>
Advanced royalties	10	\$29.4	\$7.7	\$29.4	\$4.7

Amortization of the intangible asset was \$3.0 million for the twelve months ended December 31, 2003 and 2002. SWEPCo's estimated aggregate amortization expense is \$3 million for each year 2004 through 2010 and \$1 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas – Affecting SWEPCo and TNC

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed \$3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately \$400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliation – Affecting TNC

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was \$27.5 million including interest. During the reconciliation period, TNC incurred \$293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was \$0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of \$13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of \$10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was \$6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation - Affecting TCC

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was \$63.5 million including interest. During the reconciliation period, TCC incurred \$1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of \$81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow \$140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation – Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of

January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a \$2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred \$435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than \$30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of \$8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of those deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the OPC 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. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately \$2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal – Affecting TCC

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately \$11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case – Affecting TCC

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by \$2 million or 2.5% and increase its retail energy delivery rates by \$69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested \$67 million rate increase. The recommendations range from a decrease in existing rates of approximately \$100 million to an increase in TCC's current rates of approximately \$27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately \$51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit – Affecting SWEPCO

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

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 their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints – Affecting TNC

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a \$4 million favorable adjustment recorded in December 2003. See Note 2 for a discussion of TNC's discontinuance of SFAS 71 accounting for its FERC jurisdictional customers.

Environmental Surcharge Filing – Affecting KPCo

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately \$21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

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

PSO Rate Review – Affecting PSO

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are \$36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power – Affecting PSO

PSO had a \$44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the \$44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of \$42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. 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 will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Merger Mitigation Sales – Affecting PSO, SWEPCo, TCC and TNC

As a condition of AEP/CSW merger approval at the FERC, the AEP West companies were required to mitigate market power concerns in SPP by divesting 300 MW of SPP capacity and selling 300 MW of SPP capacity at auction on an interim basis until the divestiture is completed. The margins from the interim sales were to be shared with customers in accordance with the existing margin sharing if they were positive on an annual basis and customers were to be held harmless if the margins on an annual basis were negative. Consequently, for proper accounting, the margins were deferred until year-end.

On September 1, 2003, AEP sold its share of the Eastex plant located in SPP. As a result of the sale, AEP satisfied the 300 MW FERC divestiture requirement in SPP. Based on the advice of counsel, management has concluded that it is no longer required to make the agreed upon 300 MW interim merger mitigation sale. The AEP West companies had \$8.7 million of net merger mitigation sales losses deferred. Since these sales are no longer required, the final adjustment to the accrual occurred in September 2003. The amounts of revenues reversed were \$8.6 million by PSO, \$0.7 million by TCC and \$1.2 million by TNC. SWEPCo recorded its gain of \$1.8 million as revenues.

Virginia Fuel Factor Filing – Affecting APCo

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by \$36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts – Affecting AEP East and AEP West companies

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were “high-priced.” At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid \$59 million to AEP. As a result of the contract termination, AEP reversed \$69 million of unrealized mark-to-market gains previously recorded, resulting in a \$10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. 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 requested a rehearing which the FERC 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.

RTO Formation/Integration Costs – Affecting APCo, CSPCo, I&M, KPCo, and OPCo

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately \$28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. Amounts per company are as follows:

Company	(in millions)
APCo	\$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July 2003 order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If

the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at \$24 million for the entire PJM integration project). If incurred, PJM project implementation costs will be allocated among the AEP East companies. Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately \$98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately \$13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue an initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders, directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement a new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November 2003 orders have been appealed by a number of parties. The AEP East companies received approximately \$150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months

ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order – Affecting I&M

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan – Affecting I&M

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	<u>AEGCo</u>			<u>APCo</u>		
	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period (in thousands)</u>	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period</u>
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				\$325,889	\$209,884	Various Periods (a)
Transition Regulatory Assets – Virginia				30,855	39,670	Up to 4 Years (a)
Transition Regulatory Assets – West Virginia				-	119,038	N/A
Deferred Fuel Costs				-	5,367	N/A
Unamortized Loss on Reacquired Debt	\$4,733	\$4,970	22 Years (b)	19,005	9,147	Up to 29 Years (b)
Asset Retirement Obligations	928	-	Various Periods (a)	9,048	-	Various Periods (a)
Unrealized Loss on Forward Commitments				17,006	-	Various Periods (a)
Other				15,393	12,447	Various Periods (a)
Total Regulatory Assets	<u>\$5,661</u>	<u>\$4,970</u>		<u>\$417,196</u>	<u>\$395,553</u>	
Regulatory Liabilities:						
Asset Removal Costs	\$27,822	\$-	(d)	\$92,497	\$-	(d)
Deferred Investment Tax Credits	49,589	52,943	Up to 19 Years (a)	30,545	33,691	Up to 17 Years (c)
WV Rate Stabilization Deferral				-	75,601	N/A
SFAS 109 Regulatory Liability, Net	15,505	16,670	Various Periods (a)			
Over Recovery of Fuel Costs – West Virginia				55,250	-	(a)
Unrealized Gain on Forward Commitments				17,283	-	Various Periods (a)
Over Recovery of Fuel Costs – Virginia				13,454	-	1 Year (b)
Other				43	72	Various Periods (a)
Total Regulatory Liabilities	<u>\$92,916</u>	<u>\$69,613</u>		<u>\$209,072</u>	<u>\$109,364</u>	

(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 costs will be discharged as removal costs are incurred over the life of the plant.

	CSPCo			I&M		
			Recovery/Refund			Recovery/Refund
	<u>2003</u>	<u>2002</u>	<u>Period</u> (in thousands)	<u>2003</u>	<u>2002</u>	<u>Period</u>
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	\$16,027	\$26,290	Various Periods (a)	\$151,973	\$163,928	Various Periods (a)
Transition Regulatory Assets	188,532	204,961	Up to 5 Years (a)	-	37,501	N/A
Deferred Fuel Costs				-	37,501	N/A
Unamortized Loss on			Up to 20			Up to 29
Reacquired Debt	13,659	5,978	Years (b)	18,424	14,994	Years (b)
Cook Plant Restart Costs				-	40,000	N/A
Incremental Nuclear Refueling						
Outage Expenses, Net				57,326	29,572	(c)
DOE Decontamination and						Up to 5
Decommissioning Assessment				18,863	23,375	Years (a)
Other	<u>24,966</u>	<u>20,453</u>	Various Periods (a)	<u>29,691</u>	<u>38,842</u>	Various Periods (a)
Total Regulatory Assets	<u>\$243,184</u>	<u>\$257,682</u>		<u>\$276,277</u>	<u>\$348,212</u>	
Regulatory Liabilities:						
Asset Removal Costs	\$99,119	\$-	(e)	\$263,015	\$-	(e)
Deferred Investment Tax Credits	30,797	33,907	Up to 17 Years (a)	90,278	97,709	Up to 19 Years (a)
Excess ARO for Nuclear						
Decommissioning				215,715	-	(d)
Unrealized Gain on Forward						Various
Commitments				25,010	36,804	Periods (a)
Other				<u>36,258</u>	<u>29,179</u>	Various Periods (a)
Total Regulatory Liabilities	<u>\$129,916</u>	<u>\$33,907</u>		<u>\$630,276</u>	<u>\$163,692</u>	

(a) Amount does not earn a return.

(b) Amount effectively earns a return.

(c) 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.

(d) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. Accrues monthly, will be paid when the nuclear plant is decommissioned and earns a return.

(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	KPCo			OPCo		
	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period</u> (in thousands)	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period</u>
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	\$99,828	\$87,261	Various Periods (a)	\$169,605 310,035	\$165,106 375,409	Various Periods (a)
Transition Regulatory Assets						4 years (a)
Unamortized Loss on Reacquired Debt	1,088	152	Up to 29 Years (b)	10,172	4,899	Up to 34 Years (b)
Other	<u>12,883</u>	<u>14,563</u>	Various Periods (a)	<u>22,506</u>	<u>23,227</u>	Various Periods (a)
Total Regulatory Assets	<u>\$113,799</u>	<u>\$101,976</u>		<u>\$512,318</u>	<u>\$568,641</u>	
Regulatory Liabilities:						
Asset Removal Costs	\$26,140	\$-	(c)	\$101,160	\$-	(c)
Deferred Investment Tax Credits	7,955	9,165	Up to 17 Years (a)	15,641	18,748	Up to 17 Years (a)
Unrealized Gain on Forward Commitments	9,174	10,967	Various Periods (a)			
Other	<u>1,417</u>	<u>1,185</u>	Various Periods (a)	<u>3</u>	<u>1,237</u>	Various Periods (a)
Total Regulatory Liabilities	<u>\$44,686</u>	<u>\$21,317</u>		<u>\$116,804</u>	<u>\$19,985</u>	

(a) Amount does not earn a return.

(b) 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.

	PSO			SWEPCo		
	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period</u> (in thousands)	<u>2003</u>	<u>2002</u>	<u>Recovery/Refund Period</u>
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				\$3,235	\$19,855	Various Periods (b)
Under-recovered Fuel Costs	\$24,170	\$76,470	1 Year (a)	11,394	2,865	1 Year (a)
Unamortized Loss on Reacquired Debt	14,357	11,138	Up to 12 Years (b)	19,331	17,031	Up to 40 Years (b)
Other	<u>14,342</u>	<u>15,012</u>	Various Periods (c)	<u>15,859</u>	<u>12,347</u>	Various Periods (c)
Total Regulatory Assets	<u>\$52,869</u>	<u>\$102,620</u>		<u>\$49,819</u>	<u>\$52,098</u>	
Regulatory Liabilities:						
Asset Removal Costs	\$214,033	\$-	(e)	\$236,409	\$-	(e)
Deferred Investment Tax Credits	30,411	32,201	Up to 26 Years (d)	39,864	44,190	Up to 14 Years (d)
SFAS 109 Regulatory Liability, Net	24,937	27,893	Various Periods (b)			
Over-Recovered Fuel Costs				4,178	17,226	1 Year (a)
Excess Earnings				2,600	3,700	(d)
Unrealized Gains on Forward Commitments	15,406	4,360	Various Periods (c)	11,793	1,992	Various Periods (c)
Other	<u>-</u>	<u>31</u>	Various Periods (c)	<u>6,986</u>	<u>1,402</u>	Various Periods (c)
Total Regulatory Liabilities	<u>\$284,787</u>	<u>\$64,485</u>		<u>\$301,830</u>	<u>\$68,510</u>	

- (a) Deferred fuel for PSO's Oklahoma jurisdiction & SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts do earn a return.
(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 costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	Recovery/Refund			Recovery/Refund		
	<u>2003</u>	<u>2002</u>	<u>Period</u>	<u>2003</u>	<u>2002</u>	<u>Period</u>
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	\$3,249	\$9,950	Various			
Designated For Securitization	1,253,289	330,960	Periods (a)			
Deferred Fuel Costs			(b)	\$26,680	\$26,680	(c)
Wholesale Capacity Auction						
True-up	480,000	262,000	(c)			
Unamortized Loss on			Up to 34			Up to 17
Reacquired Debt	9,086	8,661	Years (a)	3,929	3,283	Years (a)
Deferred Debt – Restructuring	12,015	13,324	Up to 14			Up to 14
DOE Decontamination and			Years (a)	6,579	10,134	Years (a)
Decommissioning Assessment	3,268	3,170	1 Year (d)			
Other	<u>130,645</u>	<u>166,931</u>	Various			Various
			Periods (e)	<u>3,332</u>	<u>5,000</u>	Periods (e)
Total Regulatory Assets	<u>\$1,891,552</u>	<u>\$794,996</u>		<u>\$40,520</u>	<u>\$45,097</u>	
Regulatory Liabilities:						
Asset Removal Costs	\$95,415	\$-	(f)	\$76,740	\$-	(f)
			Up to 25			Up to 19
Deferred Investment Tax Credits	112,479	117,686	Years (d)	19,990	21,510	Years (d)
Deferred Fuel Costs	69,026	69,026	(c)			
Retail Clawback	45,527	51,926	(c)	11,804	14,328	(c)
Over – Recovery of Transition			Up to 13			
Charges	22,499	20,870	Years (a)			
Purchased Power Conservation	9,234	9,560	Various			
			Periods (e)			
Excess Earnings	25,246	46,111	(b)	14,262	17,419	Up to 30
SFAS 109 Regulatory						Years (a)
Liability, Net				13,655	12,280	Various
			Various			Periods (a)
Other	<u>5</u>	<u>6</u>	Periods (e)	<u>1,826</u>	<u>7,285</u>	Various
						Periods (e)
Total Regulatory Liabilities	<u>\$379,431</u>	<u>\$315,185</u>		<u>\$138,277</u>	<u>\$72,822</u>	

- (a) Amount earns a return.
(b) Will be included in TCC's PUCT 2004 true-up proceedings and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory assets Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Deferred 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 complete discussion of our plans 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 Cook Plant related outage costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were \$40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately \$37 million in 2003 and \$38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 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. In connection with the merger, non-recoverable merger costs were expensed in 2003, 2002 and 2001. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2003. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense.

The following tables show the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral	Amortization Expense for
	<u>December 31, 2003</u>	<u>the Year Ended</u>
		<u>December 31, 2003</u>
	(in millions)	
I&M	\$6.7	\$1.7
KPCo	2.4	0.6
PSO	3.2	1.9
SWEPCo	2.7	1.2
TCC	6.5	2.6
TNC	1.9	0.8

	Merger Cost Deferral	Amortization Expense for
	<u>December 31, 2002</u>	<u>the Year Ended</u>
		<u>December 31, 2002</u>
	(in millions)	
I&M	\$8.2	\$1.7
KPCo	2.9	0.6
PSO	5.0	1.6
SWEPCo	3.9	1.1
TCC	9.1	2.6
TNC	2.7	0.8

	Merger Cost Deferral	Amortization Expense for
	December 31, 2001	the Year Ended
	December 31, 2001	December 31, 2001
	(in millions)	
I&M	\$9.1	\$1.7
KPCo	3.2	0.6
PSO	6.6	1.2
SWEPCo	5.0	1.1
TCC	11.8	2.6
TNC	3.5	0.8

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

<u>State/Company</u>	<u>Ratemaking Provisions</u>
Texas – SWEPCo, TCC, TNC	\$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	\$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of \$6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately \$14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately \$28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately \$28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of \$6 million over 5 years. No base rate increase before June 15, 2003.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be \$18 million over 8 years. Base rate cap until June 2005.

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

See Note 7, “Commitments and Contingencies” for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events occurring related to customer choice and industry restructuring.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a \$25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can 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 is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive 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. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The

rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate 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. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs that are in excess of \$20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the company's next distribution base rate case. The February 2004 filing provides for the continued deferrals of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, CSPCo has incurred \$32 million and deferred \$12 million and OPCo has incurred \$34 million and deferred \$14 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in each company's future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future 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.

TEXAS RESTRUCTURING – Affecting SWEPCo, TCC and TNC

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all 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 Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as

affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize \$1.27 billion of its retail generation-related regulatory assets and \$47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to \$797 million of securitization bonds (\$949 million of generation-related regulatory assets and \$33 million of qualified refinancing costs offset by \$185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's 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. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for \$43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were

not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklahoma sale and the bid information for the remaining generation, we recorded an impairment of generating assets of \$938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a \$480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the \$480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at \$6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a \$205 million over recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were \$3 million for SWEPCo, \$47 million for TCC and \$19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory

liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were \$5 million for TCC, \$3 million for TNC and \$1 million for SWEPCo.

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 has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its 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 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. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately \$9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback liability was \$45.5 million for TCC and \$11.8 million for TNC.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

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 rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 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.

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 results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

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 alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs 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 relate to costs that were incurred at the generating units over a 20-year period.

Under the Clean Air Act, 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 Clean Air Act 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 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.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken

out of service for a number of months are not “routine” maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in the AEP case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that Federal EPA bears the burden of proof on the issue of whether a practice is “routine maintenance, repair, or replacement” and on whether or not a “significant net emissions increase” results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is “routine within the relevant source category” in determining if it is “routine.” Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for similar alleged violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which the AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in the AEP case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in the AEP case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines “routine maintenance repair and replacement” to include “functionally equivalent equipment replacement.” Under the new final rule, replacement of a component within an integrated industrial operation (defined as a “process unit”) with a new component that is identical or functionally equivalent will be deemed to be a “routine replacement” if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

Management is unable to estimate the loss or range of loss related to the contingent liability 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 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, would 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.

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants – Affecting I&M and TCC

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. 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 and TCC are 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 – Affecting I&M and TCC

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at \$10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance 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 \$10 million. As a result, I&M could be assessed \$202 million per nuclear incident payable in annual installments of \$20 million. TCC could be assessed \$50 million per nuclear incident payable in annual installments of \$5 million as its share of a STPNOC assessment. 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 and TCC are also obligated for assessments of up to \$6 million and \$2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of \$1.8 billion each. I&M and STPNOC jointly purchase \$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 and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to \$43 million for I&M and \$2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal – Affecting I&M and TCC

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is

being collected from customers and remitted to the U.S. Treasury. Fees and related interest of \$226 million for fuel consumed prior to April 7, 1983 at 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, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting I&M and TCC

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, 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 Cook Plant ranges from \$821 million to \$1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. 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 and deposited in the external fund was \$27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be \$289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of \$8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional \$12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on its Consolidated Balance Sheet.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2004 – 2006 including amounts for proposed environmental rules:

(in millions)	
AEGCo	\$73.3
APCo	1,307.2
CSPCo	391.4
I&M	645.1
KPCo	153.3
OPCo	1,686.4
PSO	296.2
SWEPCo	414.3
TCC	531.2
TNC	179.9

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2007 for APCo, 2005 for CSPCo, 2007 for I&M, 2005 for KPCo, 2012 for OPCo, 2014 for PSO and 2006 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

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 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 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) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and lease the Facility to AEP. Juniper will own the Facility and lease it to AEP after construction is completed. AEP will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to 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 which is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA which TEM rejected as non-conforming.

OPCo has entered an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM, on February 11, 2004, and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately \$17.5 million. TEM may also claim that AEP is not entitled to receive any termination value for the PPA.

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 prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met 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 appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

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

Enron Bankruptcy – Affecting APCo, CSPCo, I&M, KPCo and OPCo

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

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 will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately \$93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron,

AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP expensed a total of \$53 million (\$34 million net of tax) for our estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

<u>Registrant</u>	<u>Amounts Expensed</u> (in millions)	<u>Amounts Net of Tax</u>
APCo	\$5.3	\$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. 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.

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 AEP subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges 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 alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over \$500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Energy Market Investigation – Affecting AEP System

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 has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges 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 seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial

pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design – Affecting AEP System

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until the potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation – Affecting AEP System

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 by registrant subsidiaries in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

Letters of Credit

Certain registrant subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs 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 LOCs were issued in the registrant subsidiaries' ordinary course of business. At December 31, 2003, the maximum future payments of the LOCs include \$43 million, \$1 million, \$5 million and \$4 million for TCC, I&M, OPCo and SWEPCo, respectively, with maturities ranging from March 2004 to November 2005. AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately \$58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide 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, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately \$36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine (\$78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's 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.

Indemnifications and Other Guarantees

All of the registrant subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

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, 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, 2003, 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:

Maximum Potential Loss	
<u>Subsidiary</u>	<u>(in millions)</u>
APCo	\$ 1
CSPCo	1
I&M	2
KPCo	1
OPCo	3
PSO	4
SWEPCo	4
TCC	6
TNC	2

See Note 15 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

The registrant subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling \$57.9 million pre-tax in the fourth quarter of 2002. Of this amount, the registrant subsidiaries paid \$5.0 million to

these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Other Operation expense on the registrant subsidiaries' statements of operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)	Total Termination Benefits Accrued at 12/31/02 (in millions)
AEGCo	-	\$ 0.3	\$ 0.3
APCo	93	13.1	12.2
CSPCo	19	5.0	4.5
I&M	146	15.0	13.1
KPCo	16	2.6	2.5
OPCo	33	7.5	7.1
PSO	17	3.1	3.0
SWEPCo	8	3.3	3.1
TCC	37	6.0	5.5
TNC	20	2.0	1.6

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2001

SWEPCo purchased the Dolet Hills mining operations and assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana during 2001. Management recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

Water Heater Assets – 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. We sold our water heater rental program and recorded a pre-tax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pre-tax charges in the fourth quarter 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pre-tax)	Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pre-tax) (in millions)	Loss on Sale Recorded in First Quarter 2003 (Pre-tax)
APCo	\$0.050	\$0.062	\$0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm – TNC

In the 1990's TNC developed a 6MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 TNC's engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of \$4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments on TNC's Statements of Operations.

2001

Coal Mines – OPCo

In July 2001, OPCo sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on OPCo's results of operations and cash flows.

ASSETS HELD FOR SALE

Texas Plants – TCC and TNC

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 a 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, a write-down of utility assets of approximately \$34.2 million (pre-tax) was recorded in Asset Impairments expense during the third quarter 2002 on TNC's Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately \$95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in TCC's Consolidated Balance Sheets.

During the fourth quarter 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 asset impairment charge to Asset Impairments expense of \$3.9 million (pre-tax) in the fourth quarter 2002. In addition, TNC recorded related inventory write-downs of \$2.6 million (\$1.2 million of fuel inventory in Fuel for Electric Generation expense and \$1.4 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional asset impairment write-down of \$6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets Designated for Securitization in the fourth quarter 2002. TCC also recorded related inventory write-downs of \$14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of \$38.1 million in 2002 related to TNC is included in Asset Impairments expense in TNC's Statements of Operations.

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 RMR status. During the fourth quarter of 2003, after receiving 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. In

accordance with Texas legislation, the \$938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6 “Customer Choice and Industry Restructuring” for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

	Texas Plants (TCC) (in millions)
<u>December 31, 2003</u>	
Assets:	
Current Assets	\$57
Property, Plant and Equipment, Net	797
Regulatory Assets	49
Nuclear Decommissioning Trust Fund	<u>125</u>
Total Assets Held for Sale	<u>\$1,028</u>
Liabilities:	
Regulatory Liabilities – Other	\$9
Other Noncurrent Liabilities	<u>219</u>
Total Liabilities Held for Sale	<u>\$228</u>

	Texas Plants (TCC) (in millions)
<u>December 31, 2002</u>	
Assets:	
Current Assets	\$70
Property, Plant and Equipment, Net	1,647
Nuclear Decommissioning Trust Fund	<u>98</u>
Total Assets Held for Sale	<u>\$1,815</u>
Liabilities:	
Deferred Credits and Other	<u>\$9</u>
Total Liabilities Held for Sale	<u>\$9</u>

ASSETS HELD AND USED

Blackhawk Coal Company – 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 due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the value of the investment needed to be written down based on an updated valuation reflecting management’s decision not to pursue development of potential gas reserves. As a result, a \$10.4 million charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Nonoperating Expenses in I&M’s Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWPECo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWPECo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Change in Benefit Obligation:	(in millions)			
Obligation at January 1	\$3,583	\$3,292	\$1,877	\$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	<u>(299)</u>	<u>(278)</u>	<u>(92)</u>	<u>(81)</u>
Obligation at December 31	<u><u>\$3,688</u></u>	<u><u>\$3,583</u></u>	<u><u>\$2,163</u></u>	<u><u>\$1,877</u></u>
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	\$2,795	\$3,438	\$723	\$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	<u>(299)</u>	<u>(278)</u>	<u>(92)</u>	<u>(81)</u>
Fair Value of Plan Assets at December, 31	<u><u>\$3,180</u></u>	<u><u>\$2,795</u></u>	<u><u>\$950</u></u>	<u><u>\$723</u></u>
Funded Status:				
Funded Status at December 31	\$(508)	\$(788)	\$(1,213)	\$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	<u>797</u>	<u>1,020</u>	<u>977</u>	<u>896</u>
Net Asset (Liability) Recognized	<u><u>\$279</u></u>	<u><u>\$212</u></u>	<u><u>\$(24)</u></u>	<u><u>\$(19)</u></u>

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

Accumulated Benefit Obligation:	<u>2003</u>	<u>2002</u>
	(in millions)	
U.S. Qualified Pension Plans	\$3,549	\$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
	(in millions)			
Prepaid Benefit Costs	\$325	\$255	\$-	\$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	<u>684</u>	<u>900</u>	<u>N/A</u>	<u>N/A</u>
Net Asset (Liability) Recognized	<u><u>\$279</u></u>	<u><u>\$212</u></u>	<u><u>\$(24)</u></u>	<u><u>\$(19)</u></u>
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	<u><u>\$(216)</u></u>	<u><u>\$894</u></u>	<u><u>N/A</u></u>	<u><u>N/A</u></u>

N/A = Not Applicable

The asset allocations for the U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

<u>Asset Category</u>	<u>Target Allocation</u>	<u>Percentage of Plan Assets at Yearend</u>	
	<u>2004</u>	<u>2003</u>	<u>2002</u>
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	<u>2</u>	<u>2</u>	<u>1</u>
Total	<u><u>100</u></u>	<u><u>100</u></u>	<u><u>100</u></u>

The asset allocations for the U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

<u>Asset Category</u>	<u>Target Allocation</u>	<u>Percentage of Plan Assets at Yearend</u>	
	<u>2004</u>	<u>2003</u>	<u>2002</u>
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	<u>2</u>	<u>3</u>	<u>21</u>
Total	<u><u>100</u></u>	<u><u>100</u></u>	<u><u>100</u></u>

AEP's investment strategy for the 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.

The value of the AEP qualified plans' assets increased from \$2.795 billion at December 31, 2002 to \$3.180 billion at December 31, 2003. The qualified plans paid \$292 million in benefits to plan participants during 2003 (nonqualified plans paid \$7 million in benefits). AEP's plans remain in an underfunded position (plan assets are less than projected benefit obligations) of \$508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded income in Other Comprehensive Income (OCI) of \$154 million, and a reduction in the Deferred Income Tax Asset of \$76 million, offset by a reduction to Minimum Pension Liability of \$234 million and a reduction in adjustments for unrecognized costs of \$4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of AEP's qualified plans, AEP expects to make cash contributions to the U.S. pension plans of approximately \$41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

<u>End of Year</u>	<u>U.S. Plans</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Projected Benefit Obligation	\$3,688	\$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

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.

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

	<u>U.S. Pension Plans</u>		<u>U.S. Other Postretirement Benefit Plans</u>	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
	(in percentage)			
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations AEP reviews the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, AEP determined that a decrease in its discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

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

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

<u>Employer Contributions</u>	<u>U.S. Pension Plans</u>	<u>U.S. Other Postretirement Benefit Plans</u>
	(in millions)	
2003	\$65	\$183
2004 (expected)	41	180

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

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	\$293	\$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts 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 following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)					
Service Cost	\$80	\$72	\$69	\$42	\$34	\$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	<u>11</u>	<u>(10)</u>	<u>(24)</u>	<u>52</u>	<u>27</u>	<u>18</u>
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>1</u>
Net Periodic Benefit Cost (Credit) After Curtailments	<u>\$(3)</u>	<u>\$(44)</u>	<u>\$(69)</u>	<u>\$188</u>	<u>\$142</u>	<u>\$132</u>

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	Pension Plans			Other Postretirement Benefit Plans		
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(thousands)					
APCo	\$(5,202)	\$(9,988)	\$(13,645)	\$33,618	\$25,107	\$22,810
CSPCo	(5,399)	(8,328)	(10,624)	14,684	11,494	10,328
I&M	(812)	(4,206)	(7,805)	22,999	17,608	15,077
KPCo	(566)	(1,406)	(1,922)	4,043	2,986	2,438
OPCo	(6,621)	(11,360)	(14,879)	28,143	22,608	34,444
PSO	(291)	(3,819)	(2,480)	9,885	8,436	6,187
SWEPCo	1,012	(2,245)	(3,051)	10,264	8,371	6,399
TCC	(123)	(4,786)	(3,411)	12,951	10,733	8,214
TNC	606	(1,104)	(1,644)	5,875	4,798	3,729

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

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	<u>2003</u>	<u>2002</u>	<u>2001</u> (in percentage)	<u>2003</u>	<u>2002</u>	<u>2001</u>
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	<u>2003</u> (in percentage)	<u>2002</u>
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

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

	<u>1% Increase</u>	<u>1% Decrease</u>
	(in millions)	
Effect on Total Service and Interest Cost		
Components of Net Periodic Postretirement		
Health Care Benefit Cost	\$26	\$(21)
Effect on the Health Care Component of the		
Accumulated Postretirement Benefit Obligation	315	(257)

AEP has not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on its other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on AEP's results of operations, cash flows and financial condition.

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. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. Beginning in 2001 and continuing with the single merged plan, contributions to the plans increased from 50% to 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 AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in thousands)		
APCo	\$6,450	\$ 6,722	\$7,031
CSPCo	2,745	2,784	2,789
I&M	7,616	8,039	7,833
KPCo	1,042	1,043	1,016
OPCo	5,719	5,785	6,398
PSO	2,350	2,260	2,235
SWEPCo	3,418	3,170	2,896
TCC	2,757	3,054	3,046
TNC	1,332	1,574	1,558

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by AEP and benefits are paid from AEP's general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001. In July 2001, OPCo sold certain coal mines in Ohio and West Virginia.

12. BUSINESS SEGMENTS

All of AEP's registrant subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the registrants' 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

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Registrant Subsidiaries recorded a transition adjustment to Accumulated Other Comprehensive Income (Loss) on January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Registrant subsidiaries accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. Registrant subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or a cash flow hedge. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

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 Revenues in the Consolidated Statements of Operations 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), registrant

subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in revenues during the period of change. Registrant subsidiaries recognize any ineffective portions of in revenues immediately during the period of change.

Fair Value Hedging Strategies

Certain registrant subsidiaries enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain registrant subsidiaries 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 the foreign currencies, the decline in value of future foreign currency revenue 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. Registrant subsidiaries do not hedge all foreign currency exposure.

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

Registrant subsidiaries enter into forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in thousands)
APCo	
Beginning Balance, January 1, 2003	\$(1,920)
Effective portion of changes in fair value	(448)
Reclasses from AOCI to net income	<u>799</u>
Ending Balance, December 31, 2003	<u><u>\$(1,569)</u></u>
CSPCo	
Beginning Balance, January 1, 2003	\$(267)
Effective portion of changes in fair value	194
Reclasses from AOCI to net income	<u>275</u>
Ending Balance, December 31, 2003	<u><u>\$202</u></u>
I&M	
Beginning Balance, January 1, 2003	\$(286)
Effective portion of changes in fair value	209
Reclasses from AOCI to net income	<u>299</u>
Ending Balance, December 31, 2003	<u><u>\$222</u></u>

KPCo	
Beginning Balance, January 1, 2003	\$322
Effective portion of changes in fair value	75
Reclasses from AOCI to net income	<u>23</u>
Ending Balance, December 31, 2003	<u>\$420</u>

OPCo	
Beginning Balance, January 1, 2003	\$(738)
Effective portion of changes in fair value	256
Reclasses from AOCI to net income	<u>379</u>
Ending Balance, December 31, 2003	<u>\$(103)</u>

PSO	
Beginning Balance, January 1, 2003	\$(42)
Effective portion of changes in fair value	18
Reclasses from AOCI to net income	<u>180</u>
Ending Balance, December 31, 2003	<u>\$156</u>

SWEPCo	
Beginning Balance, January 1, 2003	\$(48)
Effective portion of changes in fair value	21
Reclasses from AOCI to net income	<u>211</u>
Ending Balance, December 31, 2003	<u>\$184</u>

TCC	
Beginning Balance, January 1, 2003	\$(36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	<u>139</u>
Ending Balance, December 31, 2003	<u>\$(1,828)</u>

TNC	
Beginning Balance, January 1, 2003	\$(15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	<u>55</u>
Ending Balance, December 31, 2003	<u>\$(601)</u>

The following table approximates net gain (losses) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 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 five years.

	(in thousands)
APCo	\$1,325
CSPCo	940
I&M	1,031
KPCo	466
OPCo	1,231
PSO	724
SWEPCo	853
TCC	(1,413)
TNC	(435)

Financial Instruments

Market Valuation of Non-Derivative Financial Instrument

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, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	<u>Book Value</u>	<u>Fair Value</u>	<u>Book Value</u>	<u>Fair Value</u>
	(in thousands)		(in thousands)	
AEGCo				
Long-term Debt	\$44,811	\$47,882	\$44,802	\$48,103
APCo				
Long-term Debt	\$1,864,081	\$1,926,518	\$1,893,861	\$1,953,087
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	5,360	5,287	10,860	9,774
CSPCo				
Long-term Debt	\$897,564	\$938,595	\$621,626	\$643,715
I&M				
Long-term Debt	\$1,339,359	\$1,400,937	\$1,617,062	\$1,673,363
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	63,445	63,293	64,945	58,948
KPCo				
Long-term Debt	\$427,602	\$439,636	\$466,632	\$475,455
OPCo				
Long-term Debt	\$2,039,940	\$2,117,131	\$1,067,314	\$1,095,197
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	7,250	7,214	8,850	7,965
PSO				
Long-term Debt	\$574,298	\$589,956	\$545,437	\$570,761
Trust Preferred Securities (b)	-	-	75,000	75,900
SWEPCo				
Long-term Debt	\$884,308	\$917,982	\$693,448	\$727,085
Trust Preferred Securities (b)	-	-	110,000	110,880
TCC				
Long-term Debt	\$2,291,625	\$2,393,468	\$1,438,565	\$1,522,373
Trust Preferred Securities (b)	-	-	136,250	136,959
TNC				
Long-term Debt	\$356,754	\$374,420	\$132,500	\$144,060

(a) See Registrants Statements of Capitalization for the effect of SFAS 150 in 2003.

(b) See Note 16 on Trust Preferred Securities.

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 SNJ disposal for I&M. I&M reports trusts in “Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds” on the Consolidated Balance Sheets. TCC reports trusts in “Assets Held for Sale – Texas Generating Plants” on their Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	<u>I&M</u> (in thousands)		<u>TCC</u> (in thousands)	
	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Fair Value	\$982,400	\$870,700	\$125,400	\$98,400
Cost Basis	\$900,000	\$823,900	\$94,800	\$84,600

	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in thousands)			(in thousands)		
Net Unrealized Holding Gain (Loss)	\$35,500	\$(25,400)	\$(8,300)	\$16,700	\$(7,500)	\$(3,000)

14. INCOME TAXES

The details of the registrant subsidiaries income taxes before extraordinary items and cumulative effect of accounting changes as reported are as follows:

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2003	(in thousands)				
Charged (Credited) to Operating Expenses (net):					
Current	\$7,481	\$84,449	\$83,469	\$58,190	\$(7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	<u>1,643</u>	<u>119,589</u>	<u>84,410</u>	<u>50,926</u>	<u>12,175</u>
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	<u>(3,550)</u>	<u>(14,369)</u>	<u>(10,748)</u>	<u>(9,778)</u>	<u>(2,500)</u>
Total Income Tax as Reported	<u><u>\$(1,907)</u></u>	<u><u>\$105,220</u></u>	<u><u>\$73,662</u></u>	<u><u>\$41,148</u></u>	<u><u>\$9,675</u></u>

	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2003	(in thousands)				
Charged (Credited) to Operating Expenses (net):					
Current	\$116,316	\$55,834	\$51,564	\$88,530	\$33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	<u>(2,493)</u>	<u>(1,790)</u>	<u>(4,326)</u>	<u>(5,207)</u>	<u>(1,520)</u>
Total	<u>146,014</u>	<u>37,008</u>	<u>54,468</u>	<u>98,092</u>	<u>27,189</u>
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	<u>(614)</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>(7,615)</u>	<u>829</u>	<u>(3,396)</u>	<u>7,080</u>	<u>3,074</u>
Total Income Tax as Reported	<u>\$138,399</u>	<u>\$37,837</u>	<u>\$51,072</u>	<u>\$105,172</u>	<u>\$30,263</u>
	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2002	(in thousands)				
Charged (Credited) to Operating Expenses (net):					
Current	\$6,607	\$99,140	\$81,538	\$66,063	\$680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Credits	<u>2</u>	<u>(3,229)</u>	<u>(3,095)</u>	<u>(7,340)</u>	<u>(1,173)</u>
Total	<u>1,581</u>	<u>113,537</u>	<u>104,214</u>	<u>38,853</u>	<u>8,958</u>
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	<u>(3,363)</u>	<u>(1,408)</u>	<u>(174)</u>	<u>(400)</u>	<u>(67)</u>
Total	<u>(3,536)</u>	<u>(2,611)</u>	<u>6,789</u>	<u>5,984</u>	<u>1,904</u>
Total Income Tax as Reported	<u>\$(1,955)</u>	<u>\$110,926</u>	<u>\$111,003</u>	<u>\$44,837</u>	<u>\$10,862</u>
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2002	(in thousands)				
Charged (Credited) to Operating Expenses (net):					
Current	\$86,026	\$(49,673)	\$41,354	\$30,494	\$109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	<u>(2,493)</u>	<u>(1,791)</u>	<u>(4,524)</u>	<u>(5,206)</u>	<u>(1,271)</u>
Total	<u>113,581</u>	<u>24,195</u>	<u>33,696</u>	<u>139,014</u>	<u>(11,814)</u>
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	<u>(684)</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>18,010</u>	<u>(1,812)</u>	<u>1,772</u>	<u>3,152</u>	<u>(289)</u>
Total Income Tax as Reported	<u>\$131,591</u>	<u>\$22,383</u>	<u>\$35,468</u>	<u>\$142,166</u>	<u>\$(12,103)</u>

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2001			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	\$9,126	\$71,623	\$88,013	\$107,286	\$7,726
Deferred	(6,224)	27,198	14,923	(45,785)	2,812
Deferred Investment Tax Credits	-	(3,237)	(3,899)	(7,377)	(1,180)
Total	<u>2,902</u>	<u>95,584</u>	<u>99,037</u>	<u>54,124</u>	<u>9,358</u>
Charged (Credited) to Nonoperating Income (net):					
Current	(56)	(19,165)	(13,803)	(10,590)	(2,726)
Deferred	-	21,832	17,885	16,580	3,481
Deferred Investment Tax Credits	(3,414)	(1,528)	(159)	(947)	(71)
Total	<u>(3,470)</u>	<u>1,139</u>	<u>3,923</u>	<u>5,043</u>	<u>684</u>
Total Income Tax as Reported	<u>\$(568)</u>	<u>\$96,723</u>	<u>\$102,960</u>	<u>\$59,167</u>	<u>\$10,042</u>
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2001			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	\$(62,298)	\$53,030	\$77,965	\$190,672	\$19,424
Deferred	166,166	(16,726)	(31,396)	(72,568)	(11,891)
Deferred Investment Tax Credits	(2,495)	(1,791)	(4,453)	(5,208)	(1,271)
Total	<u>101,373</u>	<u>34,513</u>	<u>42,116</u>	<u>112,896</u>	<u>6,262</u>
Charged (Credited) to Nonoperating Income (net):					
Current	(21,600)	352	542	(1,749)	(691)
Deferred	20,014	-	-	-	-
Deferred Investment Tax Credits	(794)	-	-	-	-
Total	<u>(2,380)</u>	<u>352</u>	<u>542</u>	<u>(1,749)</u>	<u>(691)</u>
Total Income Tax as Reported	<u>\$98,993</u>	<u>\$34,865</u>	<u>\$42,658</u>	<u>\$111,147</u>	<u>\$5,571</u>

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 federal income taxes by the statutory rate, and the amount of income taxes reported.

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2003			(in thousands)		
Net Income	\$7,964	\$280,040	\$200,430	\$86,388	\$32,330
Cumulative Effect of Accounting Change	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	<u>(1,907)</u>	<u>105,220</u>	<u>73,662</u>	<u>41,148</u>	<u>9,675</u>
Pre-Tax Income	<u>\$6,057</u>	<u>\$308,003</u>	<u>\$246,809</u>	<u>\$130,696</u>	<u>\$43,139</u>
Income Tax on Pre-Tax 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	9,263	2,220	19,288	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 Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	<u>(737)</u>	<u>(5,493)</u>	<u>(8,518)</u>	<u>(10,199)</u>	<u>(4,108)</u>
Total Income Taxes as Reported	<u>\$(1,907)</u>	<u>\$105,220</u>	<u>\$73,662</u>	<u>\$41,148</u>	<u>\$9,675</u>
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2003			(in thousands)		
Net Income	\$375,663	\$53,891	\$98,141	\$217,669	\$58,557
Cumulative Effect of Accounting Change	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	<u>138,399</u>	<u>37,837</u>	<u>51,072</u>	<u>105,172</u>	<u>30,263</u>
Pre-Tax Income	<u>\$389,430</u>	<u>\$91,728</u>	<u>\$140,696</u>	<u>\$322,719</u>	<u>\$85,926</u>
Income Tax on Pre-Tax 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	4,388	1,166	834	486	286
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	<u>(3,900)</u>	<u>3,471</u>	<u>(4,403)</u>	<u>7,375</u>	<u>(1,654)</u>
Total Income Taxes as Reported	<u>\$138,399</u>	<u>\$37,837</u>	<u>\$51,072</u>	<u>\$105,172</u>	<u>\$30,263</u>
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2002			(in thousands)		
Net Income	\$7,552	\$205,492	\$181,173	\$73,992	\$20,567
Income Taxes	<u>(1,955)</u>	<u>110,926</u>	<u>111,003</u>	<u>44,837</u>	<u>10,862</u>
Pre-Tax Income	<u><u>\$5,597</u></u>	<u><u>\$316,418</u></u>	<u><u>\$292,176</u></u>	<u><u>\$118,829</u></u>	<u><u>\$31,429</u></u>
Income Tax on Pre-Tax Income at Statutory Rate (35%)	\$1,959	\$110,746	\$102,262	\$41,590	\$11,000
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State Income Taxes	335	6,469	11,387	124	1,058
Other	<u>(412)</u>	<u>(4,734)</u>	<u>(2,275)</u>	<u>(4,409)</u>	<u>(1,278)</u>
Total Income Taxes as Reported	<u><u>\$(1,955)</u></u>	<u><u>\$110,926</u></u>	<u><u>\$111,003</u></u>	<u><u>\$44,837</u></u>	<u><u>\$10,862</u></u>
Effective Income Tax Rate	N.M.	35.1%	38.0%	37.7%	34.6%
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2002			(in thousands)		
Net Income (Loss)	\$220,023	\$41,060	\$82,992	\$275,941	\$(13,677)
Income Taxes	<u>131,591</u>	<u>22,383</u>	<u>35,468</u>	<u>142,166</u>	<u>(12,103)</u>
Pre-Tax Income (Loss)	<u><u>\$351,614</u></u>	<u><u>\$63,443</u></u>	<u><u>\$118,460</u></u>	<u><u>\$418,107</u></u>	<u><u>\$(25,780)</u></u>
Income Tax on Pre-Tax Income (Loss) at Statutory Rate (35%)	\$123,065	\$22,205	\$41,461	\$146,337	\$(9,023)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	<u>(10,575)</u>	<u>(87)</u>	<u>(2,666)</u>	<u>(871)</u>	<u>(200)</u>
Total Income Taxes as Reported	<u><u>\$131,591</u></u>	<u><u>\$22,383</u></u>	<u><u>\$35,468</u></u>	<u><u>\$142,166</u></u>	<u><u>\$(12,103)</u></u>
Effective Income Tax Rate	37.4%	35.3%	29.9%	34.0%	46.9%

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2001			(in thousands)		
Net Income	\$7,875	\$161,818	\$161,876	\$75,788	\$21,565
Extraordinary Loss	-	-	30,024	-	-
Income Taxes	<u>(568)</u>	<u>96,723</u>	<u>102,960</u>	<u>59,167</u>	<u>10,042</u>
Pre-Tax Income	<u>\$7,307</u>	<u>\$258,541</u>	<u>\$294,860</u>	<u>\$134,955</u>	<u>\$31,607</u>
Income Tax on Pre-Tax Income at Statutory Rate (35%)	\$2,557	\$90,489	\$103,201	\$47,234	\$11,062
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	230	2,977	2,757	21,224	1,581
Nuclear Fuel Disposal Costs	-	-	-	(3,292)	-
Allowance for Funds Used During Construction	(1,078)	-	-	(1,606)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(420)
Investment Tax Credits (net)	(3,414)	(4,765)	(4,058)	(8,324)	(1,252)
State Income Taxes	1,050	9,613	5,727	6,137	318
Other	<u>(287)</u>	<u>(1,591)</u>	<u>(4,667)</u>	<u>(2,206)</u>	<u>(1,247)</u>
Total Income Taxes as Reported	<u>\$(568)</u>	<u>\$96,723</u>	<u>\$102,960</u>	<u>\$59,167</u>	<u>\$10,042</u>
Effective Income Tax Rate	N.M.	37.4%	34.9%	43.8%	31.8%
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2001			(in thousands)		
Net Income	\$147,445	\$57,759	\$89,367	\$182,278	\$12,310
Extraordinary Loss	18,348	-	-	-	-
Income Taxes	<u>98,993</u>	<u>34,865</u>	<u>42,658</u>	<u>111,147</u>	<u>5,571</u>
Pre-Tax Income	<u>\$264,786</u>	<u>\$92,624</u>	<u>\$132,025</u>	<u>\$293,425</u>	<u>\$17,881</u>
Income Tax on Pre-Tax Income at Statutory Rate (35%)	\$92,675	\$32,418	\$46,209	\$102,699	\$6,258
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	7,972	1,127	(501)	8,477	1,463
Investment Tax Credits (net)	(3,289)	(1,791)	(4,453)	(5,207)	(1,271)
State Income Taxes	9,752	5,137	5,451	9,652	1,283
Other	<u>(8,117)</u>	<u>(2,026)</u>	<u>(4,048)</u>	<u>(4,474)</u>	<u>(2,162)</u>
Total Income Taxes as Reported	<u>\$98,993</u>	<u>\$34,865</u>	<u>\$42,658</u>	<u>\$111,147</u>	<u>\$5,571</u>
Effective Income Tax Rate	37.4%	37.6%	32.3%	37.9%	31.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each registrant subsidiary:

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
December 31, 2003			(in thousands)		
Deferred Tax Assets	\$79,545	\$237,873	\$122,453	\$695,037	\$44,413
Deferred Tax Liabilities	<u>(103,874)</u>	<u>(1,041,228)</u>	<u>(580,951)</u>	<u>(1,032,413)</u>	<u>(256,534)</u>
Net Deferred Tax Liabilities	<u>\$(24,329)</u>	<u>\$(803,355)</u>	<u>\$(458,498)</u>	<u>\$(337,376)</u>	<u>\$(212,121)</u>
Property Related Temporary Differences	\$(62,271)	\$(623,126)	\$(357,980)	\$(74,501)	\$(151,404)
Amounts Due From Customers For					
Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)
Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other					
Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and					
Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning					
Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	<u>(1,573)</u>	<u>(39,583)</u>	<u>(26,642)</u>	<u>(17,824)</u>	<u>(7,820)</u>
Net Deferred Tax Liabilities	<u>\$(24,329)</u>	<u>\$(803,355)</u>	<u>\$(458,498)</u>	<u>\$(337,376)</u>	<u>\$(212,121)</u>
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
December 31, 2003			(in thousands)		
Deferred Tax Assets	\$192,026	\$164,801	\$163,457	\$298,648	\$67,794
Deferred Tax Liabilities	<u>(1,125,608)</u>	<u>(500,235)</u>	<u>(512,521)</u>	<u>(1,543,560)</u>	<u>(180,813)</u>
Net Deferred Tax Liabilities	<u>\$(933,582)</u>	<u>\$(335,434)</u>	<u>\$(349,064)</u>	<u>\$(1,244,912)</u>	<u>\$(113,019)</u>
Property Related Temporary Differences	\$(721,118)	\$(297,809)	\$(307,023)	\$(698,554)	\$(118,876)
Amounts Due From Customers For					
Future Federal Income Taxes	(55,143)	8,728	(5,800)	(191,615)	9,979
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning					
Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other					
Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Regulatory Assets Designated for					
Securitization	-	-	-	(281,260)	-
All Other (Net)	<u>6,110</u>	<u>(5,087)</u>	<u>(15,238)</u>	<u>13,769</u>	<u>(5,420)</u>
Net Deferred Tax Liabilities	<u>\$(933,582)</u>	<u>\$(335,434)</u>	<u>\$(349,064)</u>	<u>\$(1,244,912)</u>	<u>\$(113,019)</u>

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
December 31, 2002					
Deferred Tax Assets	\$82,889	\$247,080	\$106,597	\$436,361	\$45,231
Deferred Tax Liabilities	<u>(111,891)</u>	<u>(948,881)</u>	<u>(544,368)</u>	<u>(792,558)</u>	<u>(223,544)</u>
Net Deferred Tax Liabilities	<u>\$(29,002)</u>	<u>\$(701,801)</u>	<u>\$(437,771)</u>	<u>\$(356,197)</u>	<u>\$(178,313)</u>
Property Related Temporary Differences	\$(74,291)	\$(555,806)	\$(331,166)	\$(343,362)	\$(127,069)
Amounts Due From Customers For					
Future Federal Income Taxes	7,626	(58,246)	(8,895)	(38,752)	(20,488)
Deferred State Income Taxes	(5,119)	(77,693)	(23,448)	(52,528)	(28,722)
Transition Regulatory Assets	-	(28,735)	(71,752)	-	-
Deferred Income Taxes on Other					
Comprehensive Loss	-	38,823	31,961	21,800	5,089
Net Deferred Gain on Sale and					
Leaseback-Rockport Plant Unit 2	38,866	-	-	25,860	-
Accrued Nuclear Decommissioning	-	-	-	65,856	-
Expense					
Deferred Fuel and Purchased Power	-	(1,878)	(273)	(13,144)	415
Deferred Cook Plant Restart Costs	-	-	-	(14,000)	-
Nuclear Fuel	-	-	-	(5,153)	-
All Other (Net)	<u>3,916</u>	<u>(18,266)</u>	<u>(34,198)</u>	<u>(2,774)</u>	<u>(7,538)</u>
Net Deferred Tax Liabilities	<u>\$(29,002)</u>	<u>\$(701,801)</u>	<u>\$(437,771)</u>	<u>\$(356,197)</u>	<u>\$(178,313)</u>
	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
December 31, 2002					
Deferred Tax Assets	\$189,281	\$141,571	\$158,925	\$164,343	\$62,211
Deferred Tax Liabilities	<u>(983,668)</u>	<u>(482,967)</u>	<u>(499,989)</u>	<u>(1,425,595)</u>	<u>(179,732)</u>
Net Deferred Tax Liabilities	<u>\$(794,387)</u>	<u>\$(341,396)</u>	<u>\$(341,064)</u>	<u>\$(1,261,252)</u>	<u>\$(117,521)</u>
Property Related Temporary Differences	\$(620,019)	\$(303,888)	\$(315,821)	\$(709,246)	\$(127,038)
Amounts Due From Customers For					
Future Federal Income Taxes	(53,256)	9,490	(4,078)	(198,595)	5,726
Deferred State Income Taxes	(46,990)	(57,911)	(48,372)	(66,333)	(4,080)
Transition Regulatory Assets	(131,833)	-	-	-	-
Accrued Nuclear Decommissioning					
Expense	-	-	-	(1,117)	-
Nuclear Fuel	-	-	-	(7,023)	-
Deferred Income Taxes on Other					
Comprehensive Loss	39,246	29,332	28,906	39,394	16,565
Deferred Fuel and Purchased Power	540	(28,696)	3,192	2,655	(9,933)
Regulatory Assets Designated For					
Securitization	-	-	-	(310,410)	-
All Other (Net)	<u>17,925</u>	<u>10,277</u>	<u>(4,891)</u>	<u>(10,577)</u>	<u>1,239</u>
Net Deferred Tax Liabilities	<u>\$(794,387)</u>	<u>\$(341,396)</u>	<u>\$(341,064)</u>	<u>\$(1,261,252)</u>	<u>\$(117,521)</u>

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 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.

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 is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the

parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
Year Ended December 31, 2003	(in thousands)					
Lease Payments on						
Operating Leases	\$76,322	\$6,148	\$5,277	\$110,714	\$1,258	\$27,337
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951	9,437
Interest on Capital Leases	-	1,123	899	1,276	148	2,472
Total Lease Rental Costs	<u>\$76,591</u>	<u>\$16,488</u>	<u>\$11,074</u>	<u>\$119,360</u>	<u>\$3,357</u>	<u>\$39,246</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2003	(in thousands)			
Lease Payments on				
Operating Leases	\$4,883	\$4,708	\$6,360	\$2,132
Amortization of Capital Leases	174	1,434	161	83
Interest on Capital Leases	17	899	16	9
Total Lease Rental Costs	<u>\$5,074</u>	<u>\$7,041</u>	<u>\$6,537</u>	<u>\$2,224</u>

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
Year Ended December 31, 2002	(in thousands)					
Lease Payments on						
Operating Leases	\$76,143	\$6,634	\$5,209	\$110,833	\$1,597	\$68,816
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171	12,637
Interest on Capital Leases	19	2,240	1,717	2,221	469	4,501
Total Lease Rental Costs	<u>\$76,400</u>	<u>\$18,603</u>	<u>\$12,936</u>	<u>\$121,373</u>	<u>\$4,237</u>	<u>\$85,954</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2002	(in thousands)			
Lease Payments on				
Operating Leases	\$4,403	\$3,240	\$7,184	\$1,981
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	<u>\$4,403</u>	<u>\$3,240</u>	<u>\$7,184</u>	<u>\$1,981</u>

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
Year Ended December 31, 2001	(in thousands)					
Lease Payments on						
Operating Leases	\$76,262	\$6,142	\$7,063	\$104,574	\$1,191	\$63,913
Amortization of Capital Leases	281	12,099	7,206	17,933	2,740	14,443
Interest on Capital Leases	55	3,789	2,396	4,424	808	5,818
Total Lease Rental Costs	<u>\$76,598</u>	<u>\$22,030</u>	<u>\$16,665</u>	<u>\$126,931</u>	<u>\$4,739</u>	<u>\$84,174</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2001				
Lease Payments on				
Operating Leases	\$4,010	\$2,277	\$5,948	\$1,534
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	<u>\$4,010</u>	<u>\$2,277</u>	<u>\$5,948</u>	<u>\$1,534</u>

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Year Ended December 31, 2003					
Property, Plant and Equipment					
Under Capital Leases					
Production	\$865	\$2,758	\$7,104	\$4,492	\$1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under Capital Leases	<u>\$269</u>	<u>\$25,362</u>	<u>\$15,621</u>	<u>\$37,843</u>	<u>\$5,292</u>

Obligations Under Capital Leases:

Noncurrent Liability	\$182	\$16,134	\$11,397	\$31,315	\$3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	<u>\$269</u>	<u>\$25,352</u>	<u>\$15,618</u>	<u>\$37,843</u>	<u>\$5,292</u>

	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Year Ended December 31, 2003					
Property, Plant and Equipment					
Under Capital Leases					
Production	\$21,099	\$-	\$-	\$-	\$-
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556
Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under Capital Leases	<u>\$34,286</u>	<u>\$1,010</u>	<u>\$21,542</u>	<u>\$1,044</u>	<u>\$473</u>

Obligations Under Capital Leases:

Noncurrent Liability	\$25,064	\$558	\$18,383	\$636	\$270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	<u>\$34,688</u>	<u>\$1,010</u>	<u>\$21,542</u>	<u>\$1,043</u>	<u>\$473</u>

Year Ended December 31, 2002	<u>AEGCo</u>	<u>APCo</u> (in thousands)	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
Property, Plant and Equipment Under Capital Leases					
Production	\$1,793	\$3,368	\$6,380	\$5,728	\$1,138
Distribution	-	-	-	14,589	-
Other:					
Mining Assets and Other	-	67,395	46,791	70,140	14,258
Total Property, Plant and Equipment	1,793	70,763	53,171	90,457	15,396
Accumulated Amortization	<u>1,294</u>	<u>37,452</u>	<u>26,551</u>	<u>41,141</u>	<u>8,168</u>
Net Property, Plant and Equipment Under Capital Leases	<u>\$499</u>	<u>\$33,311</u>	<u>\$26,620</u>	<u>\$49,316</u>	<u>\$7,228</u>
Obligations Under Capital Leases:					
Noncurrent Liability	\$301	\$23,991	\$21,643	\$42,619	\$5,093
Liability Due Within One Year	<u>200</u>	<u>9,598</u>	<u>5,967</u>	<u>8,229</u>	<u>2,155</u>
Total Obligations Under Capital Leases	<u>\$501</u>	<u>\$33,589</u>	<u>\$27,610</u>	<u>\$50,848</u>	<u>\$7,248</u>

Year Ended December 31, 2002	<u>OPCo</u>	<u>SWEPCo</u> (in thousands)
Property, Plant and Equipment Under Capital Leases		
Production	\$21,360	\$-
Distribution	-	-
Other:		
Mining Assets and Other	103,018	45,699
Total Property, Plant and Equipment	124,378	45,699
Accumulated Amortization	<u>63,810</u>	<u>45,699</u>
Net Property, Plant and Equipment Under Capital Leases	<u>\$60,568</u>	<u>\$-</u>
Obligations Under Capital Leases:		
Noncurrent Liability	\$51,266	\$-
Liability Due Within One Year	<u>14,360</u>	<u>-</u>
Total Obligations Under Capital Leases	<u>\$65,626</u>	<u>\$-</u>

Future minimum lease payments consisted of the following at December 31, 2003:

	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
	(in thousands)				
Capital Leases					
2004	\$11,735	\$4,959	\$10,050	\$2,107	\$11,046
2005	6,853	4,025	7,478	1,640	8,093
2006	5,183	2,676	6,239	957	7,536
2007	2,664	1,773	12,616	785	5,582
2008	2,645	2,050	3,669	256	3,677
Later Years	<u>1,802</u>	<u>2,096</u>	<u>5,994</u>	<u>116</u>	<u>4,627</u>
Total Future Minimum Lease Payments	30,882	17,579	46,046	5,861	40,561
Less Estimated Interest Element	<u>5,530</u>	<u>1,961</u>	<u>8,203</u>	<u>569</u>	<u>5,874</u>
Estimated Present Value of Future Minimum Lease Payments	<u>\$25,352</u>	<u>\$15,618</u>	<u>\$37,843</u>	<u>\$5,292</u>	<u>\$34,687</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
	(in thousands)			
Capital Leases				
2004	\$492	\$4,737	\$450	\$223
2005	368	4,641	373	188
2006	194	4,533	198	87
2007	46	4,410	86	8
2008	4	4,389	24	1
Later Years	-	4,380	-	2
Total Future Minimum Lease Payments	1,104	27,090	1,131	509
Less Estimated Interest Element	94	5,548	88	36
Estimated Present Value of Future Minimum Lease Payments	<u>\$1,010</u>	<u>\$21,542</u>	<u>\$1,043</u>	<u>\$473</u>

	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
	(in thousands)					
Noncancellable Operating Leases						
2004	\$73,854	\$5,998	\$5,078	\$103,909	\$1,209	\$12,655
2005	73,854	5,154	4,920	97,447	1,084	11,886
2006	73,854	4,455	2,518	93,993	793	11,576
2007	73,854	3,302	2,205	91,328	771	11,132
2008	73,854	2,394	1,609	90,749	475	10,787
Later Years	1,033,956	6,094	2,726	1,096,567	1,785	66,918
Total Future Minimum Lease Payments	<u>\$1,403,226</u>	<u>\$27,397</u>	<u>\$19,056</u>	<u>\$1,573,993</u>	<u>\$6,117</u>	<u>\$124,954</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
	(in thousands)			
Noncancellable Operating Leases				
2004	\$4,684	\$5,522	\$6,112	\$1,964
2005	4,520	6,020	5,886	1,945
2006	4,079	6,844	5,218	1,846
2007	3,424	7,218	4,397	1,532
2008	1,218	7,451	3,950	1,238
Later Years	8,616	17,849	11,272	4,981
Total Future Minimum Lease Payments	<u>\$26,541</u>	<u>\$50,904</u>	<u>\$36,835</u>	<u>\$13,506</u>

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, 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 lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of \$90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG (\$469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of AEP's requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

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 are \$1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, AEGCo and I&M are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

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

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, \$321 million (\$75 million PSO, \$110 million SWEPCo and \$136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The investment in the trust is now reported as Other Investments within Other Property and Investments of \$10 million (\$2 million PSO, \$3 million SWEPCo and \$5 million TCC) and the subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt of \$331 million (\$77 million PSO, \$113 million SWEPCo and \$141 million TCC).

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

<u>Business Trust</u>	<u>Security</u>	<u>Units Issued/ Outstanding at 12/31/03</u>	<u>Amount in Other Investments at 12/31/03 (a) (in millions)</u>	<u>Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)</u>	<u>Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)</u>	<u>Description of Underlying Debentures of Registrant</u>
CPL Capital I	8.00%, Series A	5,450,000	\$5	\$141	\$136	TCC, \$141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, \$77 million, 8.00%, Series A
SWEP Co Capital I	7.875%, Series A	-	-	-	110	SWEP Co, \$113 million, 7.875%, Series A
SWEP Co Capital I	5.25%, Series B	<u>110,000</u>	<u>3</u>	<u>113</u>	<u>-</u>	SWEP Co, \$113 million, 5.25% five year fixed rate period, Series B
		<u>8,560,000</u>	<u>\$10</u>	<u>\$331</u>	<u>\$321</u>	

(a) Amounts are in Other Investments within Other Property and Investments.

(b) Amounts are in Notes Payable to Trust within Long-term Debt.

(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies 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 non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2006 for short-term borrowings sufficient to fund the utility money pool and the non-utility money pool as well as its own requirements in an amount not to exceed \$7.2 billion. Utility money pool participants include AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEP Co, TCC and TNC (domestic utility companies). The following are the SEC-authorized limits for short-term borrowings for the domestic utility companies as of December 31, 2003:

	<u>Authorized (in millions)</u>
AEP Generating Company	\$125
AEP Texas Central Company (a)	438
AEP Texas North Company (a)	275
Appalachian Power Company	600
Columbus Southern Power Company (a)	150
Indiana Michigan Power Company	500
Kentucky Power Company	200
Ohio Power Company (a)	200
Public Service Company of Oklahoma	300
Southwestern Electric Power Company	350

(a) Short-term borrowing limits for these domestic utility companies are reduced by long-term debt issued commencing with the SEC order dated December 18, 2002, which authorized financing transactions through March 31, 2006.

As of December 31, 2003, AEP had credit facilities totaling \$2.9 billion to support its commercial paper program. At December 31, 2003, AEP had \$326 million outstanding in short-term borrowings of which \$282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of \$26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 15 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was \$1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Net interest income (expense) recorded by each registrant subsidiary related to amounts advanced to (borrowed from) the AEP money pool were:

	<u>Year Ended December 31,</u>		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
AEGCo	\$(0.3)	\$(0.2)	\$(0.7)
APCo	1.4	(4.1)	(9.9)
CSPCo	-	(1.1)	(4.9)
I&M	1.5	1.0	(12.6)
KPCo	(0.9)	(1.6)	(2.3)
OPCo	(1.6)	(5.7)	(13.2)
PSO	(1.1)	(4.1)	(5.8)
SWEPCo	0.1	(2.8)	(2.3)
TCC	-	(6.3)	(11.1)
TNC	(0.3)	(3.2)	(3.0)

Outstanding short-term debt for AEP Consolidated consisted of:

	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Balance Outstanding:		
Notes Payable	\$18	\$1,322
Commercial Paper – AEP	282	1,417
Commercial Paper – JMG	<u>26</u>	<u>-</u>
Total	<u>\$326</u>	<u>\$2,739</u>

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, 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 does not consolidate these entities in accordance with GAAP. We continue 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 extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement

provides commitments of \$600 million to purchase receivables from AEP Credit. At December 31, 2003, \$385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the 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 and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCCo, 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. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company) were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Proceeds from Sale of Accounts Receivable	\$5,221	\$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	<u>Face Value</u>	
	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in millions)	
Customer Accounts Receivable Retained	\$1,155	\$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	<u>(124)</u>	<u>(108)</u>
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	<u>385</u>	<u>454</u>
Total Accounts Receivable Managed	<u>\$2,095</u>	<u>\$2,543</u>
Net Uncollectible Accounts Written Off	<u>\$39</u>	<u>\$48</u>

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.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was \$30 million.

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 as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each registrant subsidiary was as follows:

	December 31,	
	<u>2003</u>	<u>2002</u>
	(in millions)	
APCo	\$60.2	\$67.6
CSPCo	100.2	114.3
I&M	93.0	103.7
KPCo	30.4	29.5
OPCo	99.3	109.8
PSO	99.6	83.7
SWEPCo	64.4	65.2

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	<u>2003</u>	<u>2002</u>	<u>2001</u>
	(in millions)		
APCo	\$3.4	\$ 4.8	\$ 5.2
CSPCo	9.8	15.8	15.2
I&M	6.1	7.4	8.5
KPCo	2.4	2.7	2.7
OPCo	8.7	11.4	12.8
PSO	5.8	7.2	9.6
SWEPCo	4.9	5.4	7.4
TCC	-	2.2	14.7
TNC	-	1.4	3.8

17. RELATED PARTY TRANSACTIONS

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 SO2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with FERC, under certain conditions CSPCo and OPCo would no longer be parties to the Interconnection Agreement and certain other modifications to its terms would also be made.

Power and Gas and risk management activities are conducted by the AEP Power Pool and 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 and the risk management of electricity and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

AEP West Companies

PSO, SWEPCo, TCC, TNC operating companies of the west zone and AEPSC 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 AEP West operating companies to maintain specified 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. The CSW Operating Agreement also delegates to AEPSC 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, under certain conditions TCC and TNC would no longer be parties to the CSW Operating Agreement.

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.

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2003, 2002 and 2001:

	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>	<u>AEGCo</u>
Related Party Revenues			(in thousands)			
2003 Sales to East System Pool	\$130,921	\$59,113	\$228,667	\$32,827	\$503,334	\$-
Sales to West System Pool	27	9	17	6	21	-
Direct Sales To East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales To West Affiliates	27,951	16,428	17,674	6,425	21,759	-
Other	3,256	8,819	2,845	550	8,400	-
Total Revenues	<u>\$222,793</u>	<u>\$84,369</u>	<u>\$249,203</u>	<u>\$39,808</u>	<u>\$584,278</u>	<u>\$232,955</u>
2002 Sales to East System Pool	\$106,651	\$42,986	\$197,525	\$22,369	\$397,248	\$-
Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
Direct Sales To East Affiliates	58,213	-	-	-	50,599	213,071
Direct Sales To West Affiliates	-	-	-	-	-	-
Other	3,313	2,109	3,577	878	1,090	-
Total Revenues	<u>\$186,477</u>	<u>\$57,202</u>	<u>\$214,138</u>	<u>\$27,964</u>	<u>\$465,202</u>	<u>\$213,071</u>
2001 Sales to East System Pool	\$91,977	\$44,185	\$239,277	\$34,735	\$431,637	\$-
Sales to West System Pool	24,892	13,971	15,596	6,117	19,797	-
Direct Sales To East Affiliates	54,777	-	-	-	55,450	227,338
Direct Sales To West Affiliates	(3,133)	(1,705)	(1,905)	(744)	(2,590)	-
Other	2,772	11,060	2,071	2,258	7,072	-
Total Revenues	<u>\$171,285</u>	<u>\$67,511</u>	<u>\$255,039</u>	<u>\$42,366</u>	<u>\$511,366</u>	<u>\$227,338</u>

		<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Related Party Revenues		(in thousands)			
2003	Sales to East System Pool	\$-	\$-	\$-	\$-
	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	<u>3,323</u>	<u>2,746</u>	<u>114,486</u>	<u>52,567</u>
	Total Revenues	<u>\$23,130</u>	<u>\$68,854</u>	<u>\$153,568</u>	<u>\$55,153</u>
2002	Sales to East System Pool	\$-	\$-	\$-	\$-
	Sales to West System Pool	674	1,334	18,416	1,280
	Direct Sales To East Affiliates	611	270	366	(23)
	Direct Sales To West Affiliates	6,047	75,674	956,751	228,404
	Other	<u>2,107</u>	<u>(4,979)</u>	<u>32,911</u>	<u>10,764</u>
	Total Revenues	<u>\$9,439</u>	<u>\$72,299</u>	<u>\$1,008,444</u>	<u>\$240,425</u>
2001	Sales to East System Pool	\$4	\$-	\$-	\$-
	Sales to West System Pool	3,317	8,073	19,865	322
	Direct Sales To East Affiliates	2,833	3,238	3,697	1,228
	Direct Sales To West Affiliates	30,668	67,930	12,617	9,350
	Other	<u>(51)</u>	<u>(4)</u>	<u>5,583</u>	<u>7,781</u>
	Total Revenues	<u>\$36,771</u>	<u>\$79,237</u>	<u>\$41,762</u>	<u>\$18,681</u>

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2003, 2002, and 2001:

		<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>OPCo</u>
Related Party Purchases		(in thousands)				
2003	Purchases from East System Pool	\$348,899	\$335,916	\$109,826	\$71,259	\$88,962
	Purchases from West System Pool	-	-	-	-	-
	Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
	Direct Purchases from West Affiliates	<u>765</u>	<u>471</u>	<u>505</u>	<u>182</u>	<u>625</u>
	Total Purchases	<u>\$351,210</u>	<u>\$337,323</u>	<u>\$274,400</u>	<u>\$141,690</u>	<u>\$90,821</u>
2002	Purchases from East System Pool	\$233,677	\$309,999	\$83,918	\$68,846	\$70,338
	Purchases from West System Pool	337	219	237	86	297
	Direct Purchases from East Affiliates	583	387	149,569	64,070	519
	Direct Purchases from West Affiliates	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
	Total Purchases	<u>\$234,597</u>	<u>\$310,605</u>	<u>\$233,724</u>	<u>\$133,002</u>	<u>\$71,154</u>
2001	Purchases from East System Pool	\$346,582	\$292,034	\$79,030	\$61,816	\$62,350
	Purchases from West System Pool	296	165	185	72	235
	Direct Purchases from East Affiliates	-	-	159,022	68,316	-
	Direct Purchases from West Affiliates	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
	Total Purchases	<u>\$346,878</u>	<u>\$292,199</u>	<u>\$238,237</u>	<u>\$130,204</u>	<u>\$62,585</u>

	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
Related Party Purchases			(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	<u>\$109,639</u>	<u>\$47,914</u>	<u>\$19,097</u>	<u>\$39,409</u>
2002 Purchases from East System Pool	\$343	\$-	\$-	\$-
Purchases from West System Pool	874	(456)	1,366	15,475
Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
Direct Purchases from West Affiliates	<u>59,208</u>	<u>25,236</u>	<u>13,804</u>	<u>19,438</u>
Total Purchases	<u>\$89,454</u>	<u>\$42,022</u>	<u>\$23,406</u>	<u>\$37,582</u>
2001 Purchases from East System Pool	\$1,327	\$-	\$-	\$4
Purchases from West System Pool	5,877	3,810	415	11,689
Direct Purchases from East Affiliates	1,951	2,352	12,657	4,614
Direct Purchases from West Affiliates	<u>34,603</u>	<u>9,696</u>	<u>45,569</u>	<u>40,349</u>
Total Purchases	<u>\$43,758</u>	<u>\$15,858</u>	<u>\$58,641</u>	<u>\$56,656</u>

The above summarized related party revenues and expenses are reported in their entirety, without elimination, and are presented as operating revenues affiliated and purchased power affiliated on the statements of operations 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 (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
		(in thousands)	
APCo	\$-	\$(13,400)	\$(3,100)
CSPCo	38,200	42,200	40,200
I&M	(39,800)	(36,100)	(41,300)
KPCo	(5,600)	(5,400)	(4,600)
OPCo	7,200	12,700	8,800

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established 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 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 west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net (credits) or charges allocated among parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	<u>2003</u>	<u>2002</u> (in thousands)	<u>2001</u>
PSO	\$4,200	\$4,200	\$4,000
SWEPCo	5,000	5,000	5,400
TCC	(3,600)	(3,600)	(3,900)
TNC	(5,600)	(5,600)	(5,500)

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.

AEP Coal, Inc.

AEP Coal, Inc. and CSPCo are parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provides for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from \$23.15 per ton to \$26.15 per ton plus quality adjustments. In 2002, AEP Coal, Inc. and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from \$24.00 per ton to \$27.00 per ton plus quality adjustments. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of \$23.9 million and \$21 million, respectively.

AEP Coal, Inc. and CSPCo are parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transfers coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivers the coal via trucks to CSPCo's Conesville Preparation Plant or CSPCo's Power Plant for a rate of \$1.25 per ton and \$1.03 per ton, respectively. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of \$3.4 million and \$3.5 million, respectively.

AEP East Companies

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East operating 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 operating 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 subsidiary liabilities at December 31, 2003 in thousands:

APCo	\$(32,287)
CSPCo	(18,185)
I&M	(19,932)
KPCo	(7,349)
OPCo	<u>(24,055)</u>
Total	<u>\$(101,808)</u>

Unit Power Agreements and Other

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) 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. 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 expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating 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:

Company	Year Ended December 31,		
	<u>2003</u>	<u>2002</u> (in millions)	<u>2001</u>
I&M – revenues	\$31.9	\$34.3	\$30.2
AEGCo – expense	8.1	7.8	8.5
APCo – expense	12.3	12.8	11.5
KEPCo – expense	0.1	-	-
OPCo – expense	4.3	7.9	10.2
MEMCo – expense (Non-Utility subsidiary of AEP)	7.1	5.7	-
AEP Energy Services (Non-Utility subsidiary of AEP)	-	0.1	-

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the plant, which is owned by NPC. The plant went into service in July 2002. Because APCo, CSPCo, I&M, KPCo and OPCo purchase 100% of the available generating capacity from the plant, they also share in paying fuel expense to AEPES. The related purchases from AEPES were as follows:

	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in thousands)	
KPCo	\$363	\$150
I&M	1,000	418
CSPCo	936	387
OPCo	1,234	519
APCo	<u>1,546</u>	<u>583</u>
Total	<u>\$5,079</u>	<u>\$2,057</u>

There was no activity in 2001.

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related sales are as follows:

	<u>Year Ended December 31,</u>	
	<u>2003</u>	<u>2002</u>
	(in thousands)	
TCC	\$195,527	\$157,346
TNC	44,197	64,385

There was no activity in 2001.

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 shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly owned with affiliated and unaffiliated 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 AEP 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,			
		2003		2002	
	Percent of Ownership	Utility Plant in Service (in thousands)	Construction Work in Progress (in thousands)	Utility Plant in Service (in thousands)	Construction Work in Progress (in thousands)
<u>CSPCo</u>					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	\$15,455	\$127	\$15,487	\$49
Conesville Generating Station (Unit No. 4)	43.5	82,115	722	81,960	279
J.M. Stuart Generating Station	26.0	204,820	50,326	197,276	44,865
Wm. H. Zimmer Generating Station	25.4	707,281	31,249	705,620	14,077
Transmission	(a)	<u>62,061</u>	<u>742</u>	<u>61,187</u>	<u>2,281</u>
Total		<u>\$1,071,732</u>	<u>\$83,166</u>	<u>\$1,061,530</u>	<u>\$61,551</u>
<u>PSO</u>					
Oklaunion Generating Station (Unit No. 1)	15.6	<u>\$85,064</u>	<u>\$518</u>	<u>\$83,562</u>	<u>\$777</u>
<u>SWEPCo</u>					
Dolet Hills Generating Station (Unit No. 1)	40.2	\$236,116	\$2,304	\$235,366	\$1,313
Flint Creek Generating Station (Unit No. 1)	50.0	93,309	737	91,567	1,052
Pirkey Generating Station (Unit No. 1)	85.9	<u>454,303</u>	<u>3,125</u>	<u>451,136</u>	<u>2,197</u>
Total		<u>\$783,728</u>	<u>\$6,166</u>	<u>\$778,069</u>	<u>\$4,562</u>
<u>TCC (b)</u>					
Oklaunion Generating Station (Unit No. 1)	7.8	\$38,798	\$252	\$38,055	\$369
South Texas Project Generation Station (Units No. 1 and 2)	25.2	<u>2,386,579</u>	<u>934</u>	<u>2,364,359</u>	<u>43,887</u>
Total		<u>\$2,425,377</u>	<u>\$1,186</u>	<u>\$2,402,414</u>	<u>\$44,256</u>
<u>TNC</u>					
Oklaunion Generating Station (Unit No. 1)	54.7	<u>\$285,314</u>	<u>\$1,351</u>	<u>\$277,946</u>	<u>\$3,650</u>

(a) Varying percentages of ownership.

(b) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31,	
	<u>2003</u>	<u>2002</u>
	(in thousands)	
CSPCo	\$435,249	\$436,683
PSO	50,968	49,085
SWEPCo	465,871	450,057
TCC (a)	991,665	927,193
TNC	103,642	102,542

(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 AEP registrant subsidiary follows:

<u>Quarterly Periods Ended</u>	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
	(in thousands)				
<u>March 31, 2003</u>					
Operating Revenues	\$60,428	\$536,228	\$359,205	\$418,598	\$112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
<u>June 30, 2003</u>					
Operating Revenues	\$59,568	\$444,751	\$333,071	\$376,906	\$95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
<u>September 30, 2003</u>					
Operating Revenues	\$59,008	\$483,611	\$397,655	\$423,004	\$103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
<u>December 31, 2003</u>					
Operating Revenues	\$54,161	\$492,768	\$341,920	\$377,088	\$105,219
Operating Income	2,000	89,937	55,725	51,606	20,849
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

<u>Quarterly Periods Ended</u>	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
		(in thousands)			
<u>March 31, 2003</u>					
Operating Revenues	\$590,631	\$242,662	\$255,278	\$428,358	\$116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
<u>June 30, 2003</u>					
Operating Revenues	\$539,386	\$277,236	\$281,306	\$482,446	\$136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
<u>September 30, 2003</u>					
Operating Revenues	\$565,318	\$358,575	\$361,622	\$485,129	\$114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
<u>December 31, 2003</u>					
Operating Revenues	\$549,318	\$224,349	\$248,636	\$351,578	\$98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

<u>Quarterly Periods Ended</u>	<u>AEGCo</u>	<u>APCo</u>	<u>CSPCo</u>	<u>I&M</u>	<u>KPCo</u>
	(in thousands)				
<u>March 31, 2002</u>					
Operating Revenues	\$49,875	\$462,605	\$314,826	\$352,235	\$99,185
Operating Income	1,767	81,554	45,548	30,363	15,484
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,893	55,341	33,858	11,058	10,246
Net Income	1,893	55,341	33,858	11,058	10,246
<u>June 30, 2002</u>					
Operating Revenues	\$53,356	\$432,015	\$343,813	\$369,043	\$92,164
Operating Income	1,504	65,224	58,040	19,865	9,550
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,718	46,608	51,721	7,494	5,246
Net Income	1,718	46,608	51,721	7,494	5,246
<u>September 30, 2002</u>					
Operating Revenues	\$55,988	\$464,409	\$421,892	\$414,414	\$97,811
Operating Income	1,436	81,365	89,033	57,004	11,119
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,947	53,947	76,117	35,312	5,994
Net Income	1,947	53,947	76,117	35,312	5,994
<u>December 31, 2002</u>					
Operating Revenues	\$54,062	\$455,441	\$319,629	\$391,072	\$89,523
Operating Income	1,422	73,920	27,158	43,957	6,044
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,994	49,596	19,477	20,128	(919)
Net Income (Loss)	1,994	49,596	19,477	20,128	(919)

<u>Quarterly Periods Ended</u>	<u>OPCo</u>	<u>PSO</u>	<u>SWEPCo</u>	<u>TCC</u>	<u>TNC</u>
	(in thousands)				
<u>March 31, 2002</u>					
Operating Revenues	\$520,652	\$148,986	\$222,259	\$278,910	\$103,626
Operating Income	83,716	8,410	22,469	55,445	11,145
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	64,051	(1,648)	8,159	24,445	3,992
Net Income (Loss)	64,051	(1,648)	8,159	24,445	3,992
<u>June 30, 2002</u>					
Operating Revenues	\$521,365	\$158,330	\$263,074	\$360,391	\$104,452
Operating Income	61,046	20,201	31,988	64,319	5,547
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,348	11,620	18,155	33,535	675
Net Income	55,348	11,620	18,155	33,535	675
<u>September 30, 2002</u>					
Operating Revenues	\$557,574	\$230,098	\$362,423	\$546,260	\$152,667
Operating Income (Loss)	97,210	50,710	60,254	118,204	(308)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	80,258	41,002	45,794	93,383	(4,193)
Net Income (Loss)	80,258	41,002	45,794	93,383	(4,193)
<u>December 31, 2002</u>					
Operating Revenues	\$513,534	\$256,233	\$236,964	\$504,932	\$89,995
Operating Income (Loss)	56,357	5,400	27,758	155,765	(8,513)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	20,366	(9,914)	10,884	124,578	(14,151)
Net Income (Loss)	20,366	(9,914)	10,884	124,578	(14,151)

For each of the AEP registrant subsidiaries, there were no significant, non-recurring events in the fourth quarter of 2003 or 2002.

20. **SUBSEQUENT EVENTS (UNAUDITED)**

After December 31, 2003 we entered into separate agreements to dispose of the following investments:

<u>Investment</u>	<u>Sales Price</u> (in millions)	<u>Date of Agreement</u>
Oklunion Power Station (TCC's 7.8% ownership interest)	\$42.8	January 30, 2004
STP (TCC's 25.2% ownership interest)	\$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

REGISTRANTS' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

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 AEP's electric subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its 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 electric 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 their parent company.

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. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be removed from 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 does not consolidate these entities in accordance with GAAP. The electric subsidiaries continue 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 extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of \$600 million to purchase receivables from AEP Credit. At December 31, 2003, \$385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the 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. In addition, the purchase agreements between AEP Credit and TCC and TNC were terminated effective March 20, 2002.

Budgeted Construction Expenditures

Construction expenditures for certain registrant subsidiaries for the next three years are:

	<u>Projected Construction Expenditures (in millions)</u>	<u>Construction Expenditures Financed With Internal Funds</u>
APCo	\$1,307	70%
I&M	645	100
OPCo	1,686	60
SWEPCo	414	100
TCC	531	100

Significant Factors

Possible Divestitures

AEP's management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC is seeking to divest significant components of its non-regulated domestic generation assets. In June 2003, TCC began actively seeking buyers for 4,497 megawatts of its generating capacity in Texas. The value received from this disposition will also be used to calculate stranded costs in Texas (see Note 6). Management is currently evaluating bids received during the fourth quarter of 2003 and is in negotiations to sell these assets. See Note 10 for discussion of impairments recorded related to the generating units in Texas. The ultimate sale of these assets may have a material impact on results of operations, cash flows and financial condition if losses are not recovered through the 2004 true-up proceeding in Texas.

Management continues to have periodic discussions with various parties on business alternatives for certain other investments. The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal.

Corporate Separation

In compliance with certain provisions in the Texas and Ohio restructuring laws, AEP filed in 2001 for regulatory approvals related to efforts at that time to separate regulated and unregulated operations, and amend certain affiliate pooling arrangements. Although certain regulatory approvals have been obtained, with the changes in the regulatory environment and AEP's business strategy, management continues to evaluate corporate separation plans.

In Texas, TCC is in the process of divesting its generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which management expect to be finalized in 2004, TCC will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of AEP's states requires RTO participation.

In May 2002, AEP announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, AEP's subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately \$98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately \$13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, they are committed to reimburse PJM for certain project implementation costs (presently estimated at \$24 million for AEP's share of the entire PJM integration project). These costs, if incurred, will be allocated to the AEP East companies. AEP East companies also plan to seek recovery of deferred RTO formation/integration costs in the future. At December 31, 2003, the deferred amounts per company are as follows:

Company	(in millions)
APCo	\$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate AEP's SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at the FERC for recognition as an RTO. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

AEP maintains qualified defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess 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's net periodic pension expense was an income item for all pension plans approximating \$3 million and \$44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. 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 the 10-year average return, for the period ended December 2003, of approximately 10.0%. AEP anticipates that the investment managers it employs for the pension fund will continue to generate long-term returns of at least 8.75%.

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

	2003 Actual <u>Asset Allocation</u>	2004 Target <u>Asset Allocation</u> (in percentage)	Assumed/Expected Long-term Rate <u>of Return</u>
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	<u>2</u>	<u>2</u>	2
Total	<u>100</u>	<u>100</u>	
Overall Expected Return (weighted average)			<u>8.75</u>

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. AEP believes that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. 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, 2003, AEP has cumulative losses of approximately \$325 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 discount rate that AEP utilizes for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, AEP estimates that the pension expense for all pension plans will approximate \$41 million, \$78 million and \$103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately \$18 million (income of \$3 million would have become \$15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately \$0.5 million.

The value of the Qualified Plans' assets has increased from \$2.795 billion at December 31, 2002 to \$3.180 billion at December 31, 2003. The Qualified Plans paid out \$292 million in benefits to plan participants during 2003 (the nonqualified plans paid out \$7 million in benefits). AEP's pension plans remain in an underfunded position (plan assets are less than projected benefit obligations) of \$508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded a charge to Other Comprehensive Income (OCI) of \$585 million in 2002, and recorded a Deferred Income Tax Asset of \$315 million, offset by a Minimum Pension Liability of \$662 million and a reduction to prepaid costs and adjustment for unrecognized costs of \$238 million. In 2003, the income recorded in OCI was \$154 million, and the reduction in the Deferred Income Tax Asset was \$76 million, offset by a reduction in Minimum Pension Liability of \$234 million and a reduction to adjustment for

unrecognized costs of \$4 million. The charge to OCI does not affect earnings or cash flow. AEP's plans are in compliance with the laws and regulations governing such plans including the Employee Retirement Income Security Act of 1974, as amended. Due to the current underfunded status of the Qualified Plans, AEP expects to make cash contributions to the pension plans of approximately \$41 million in 2004.

Certain of the defined benefit 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, 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 substantial compliance with the applicable requirements of such laws.

See Note 11 of the Notes to Respective Financial Statements for additional information related to the impact of pension plans on individual AEP registrant subsidiaries.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. TCC's share of the cost of repair for this outage was approximately \$6 million. TCC had commitments to provide power to customers during the outage. Therefore, TCC was subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately \$125 million plus interest in connection with gas related trading transactions. AEP will assert its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately \$93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP subsidiaries expensed a total of \$53 million (\$34 million net of tax) for their estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts <u>Expensed</u> (in millions)	Amounts Net of <u>Tax</u>
APCo	\$5.3	\$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amounts expensed were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. 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.

Energy Market Investigations

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 has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, AEP received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, AEP received an informal data request from the SEC seeking that AEP voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. AEP responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges 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 seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, AEP recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. AEP is responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

TEM Litigation

See discussion of TEM litigation within OPCo's Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, certain unaffiliated energy companies and ERCOT alleging 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 alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over \$500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against AEP and its subsidiaries are without merit. Management intends to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a \$319 million reduction in AEP's Net Income for 2000.

The earnings reductions for affected registrant subsidiaries were as follows:

	(in millions)
APCo	\$82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

AEP filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Other Litigation

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

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 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 recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that management expects will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO₂), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

- New Clean Water Act rules 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 emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over \$2 billion, from 1990 through 2003, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its generating stations because this is the most cost-effective generation source for its customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as “national ambient air quality standards” (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state’s SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states’ SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NO_x Rule in 1997, which affected 22 eastern states (including states in which AEP subsidiaries operate) and the District of Columbia. The NO_x Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NO_x emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

AEP subsidiaries are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO₂ and particulate matter emissions in all states, and that control NOx emissions in certain states. The AEP System's generating plants comply with applicable SIP limits for SO₂, NOx and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO₂, NOx, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO₂ emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO₂ emissions of 8.9 million tons per year. The Federal EPA administers its SO₂ program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO₂ that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NO_x emissions through the use of available combustion controls. Units must meet NO_x emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO₂, NO_x, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO₂ and NO_x emissions as precursors to the formation of fine particulate matter. NO_x emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO_x and SO₂ from the AEP System's generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NO_x, SO₂, and mercury emissions from electric generating plants. AEP supports enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require the AEP System to substantially reduce SO₂, NO_x and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO₂, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO₂ and NO_x emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NO_x and SO₂ emissions from coal-fired electric utility units. SO₂ and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO₂ emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO_x emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO₂ and NO_x trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no

commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO₂ (scrubbers) and NO_x (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO₂ and NO_x reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO₂ and NO_x requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO₂, NO_x and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

All of management's 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
- Selected compliance alternatives.

As a result, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to the AEP subsidiaries' current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NOx Compliance

Management estimates that AEP subsidiaries will make future investments of approximately \$600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately \$500 million of these investments are reflected in the estimated construction expenditures for 2004 – 2006. As of December 31, 2003, the AEP System has invested approximately \$1.1 billion to comply with various NOx requirements. Estimated future compliance costs, amounts in the 2004 – 2006 construction budget and amounts spent by subsidiaries are as follows:

	<u>Future Estimated Compliance Investment</u>	<u>Investment Amount in 2004 – 2006 Budget</u> (in millions)	<u>Amount Spent</u>
AEGCo	\$10	\$9	\$12
APCo	151	151	307
CSPCo	63	29	71
I&M	10	9	17
KPCo	11	1	179
OPCo	305	273	442
PSO	8	8	-
SWEPCo	18	12	23
TCC	-	-	5

Estimated Investments for SO2 Compliance

The AEP System is complying with Title IV SO₂ requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO₂ allowances that were:

- Received in the annual allowance allocation by the Federal EPA,
- Obtained through participation in the annual allowance auction,
- Purchased in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO₂ allowance allocations, a diminishing SO₂ allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO₂ obligations. In total management estimates these additional capital costs to be approximately \$1.2 billion. Of this total, approximately \$900 million will be expended during 2004-2006 and this amount is included in total estimated construction expenditures for 2004 – 2006. The following table shows the estimated additional capital costs and amounts included in the 2004 – 2006 budget for additional scrubbers by subsidiary:

	<u>Cost of Additional Scrubbers</u>	<u>Amount in 2004 – 2006 Construction Budget</u> (in millions)
APCo	\$367	\$307
OPCo	753	542
SWEPCo	27	21
TNC	16	16

Estimated Investments to Comply with Future Reduction Requirements

The AEP System's planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. Management has also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO₂, NO_x and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately \$1.7 billion by 2010, the end of the first phase for each proposed rule. Management estimates that the subsidiaries will invest \$200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

	<u>Estimated Compliance Investments</u>	<u>Amount in 2004 – 2006 Budget</u>
	(in millions)	
APCo	\$698	\$79
CSPCo	184	4
KPCo	295	36
OPCo	454	103
SWEPCo	94	-

Management also estimates that the subsidiaries would incur increases in variable operation and maintenance expenses of \$150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

If the Federal EPA's preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would also have implementation costs that could be significant. Management cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that the AEP System operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which management is not able to estimate, would be incremental to other cost estimates that are discussed above.

Beyond 2010, the AEP System expects to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. Management cannot estimate these additional costs because of the uncertainties associated with the final control requirements and the associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

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 Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs 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 relate to costs that were incurred at the generating units over a 20-year period.

Management is unable to estimate the loss or range of loss related to the contingent liability 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 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, would 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.

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 disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generation plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. AEP subsidiaries are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, APCo, CSPCo, I&M and OPCo are each named by the Federal EPA as a PRP for one site. There are six additional sites for which APCo, CSPCo, I&M, KPCo, OPCo and SWEPCo have received information requests which could lead to PRP designation. OPCo and TCC have also been named potentially liable at four sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding potential future liability. Disposal of materials by an AEP subsidiary 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 AEP subsidiaries have been declared PRPs. If significant cleanup costs are attributed to any AEP subsidiary in the future under Superfund, its results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in its electricity prices.

Global Climate Change

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 CO₂, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO₂ and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO₂ or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

AEP does not support the Kyoto Protocol but has been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which AEP's subsidiaries are obligated to reduce or offset 18 million tons of CO₂ emissions during 2003-2006.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected \$316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited \$117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted \$199 million to the DOE. TCC has collected and remitted to the DOE, \$56 million for the future disposal of SNF since STP began operation in the late 1980s. 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. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, the DOE has failed to comply with 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, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of unaffiliated 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 the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M 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 August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from \$821 million to \$1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was \$720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC's share of decommissioning cost to be \$289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2003, the total decommissioning trust fund for TCC's share of STP was \$125 million which includes earnings on the trust investments. Estimates from the decommissioning studies 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 and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, 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.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

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, the AEP 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 Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ significantly from those estimates under different assumptions and conditions. We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), 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. In accordance with SFAS 71, 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 through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in 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 mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into 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.

After January 1, 2003, registrant subsidiaries use mark-to-market 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. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

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

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions, registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Registrant subsidiaries designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). Registrant subsidiaries report changes in the fair value of these instruments on our balance sheet. Registrant subsidiaries do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. Registrant subsidiaries also recognize any changes in the fair value of the hedging instrument, that are not offset by changes in the fair value of the hedged item, immediately in earnings.

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statements on a net basis.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. 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.

Pension Benefits

AEP sponsors pension and other retirement plans in various forms covering all employees who meet eligibility requirements. AEP uses several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to its plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, AEP's actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in the Significant Factors section of Registrants' Combined Management's Discussion and Analysis for additional discussion.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company (\$77.8 million) and JMG Funding, LP (\$469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries (\$321 million). As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The

FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 of the Notes to Respective Financial Statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

The sale of electric power in AEP subsidiaries' service territories 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 the AEP System's facilities and the terms of power contracts into which AEP enters. In addition, AEP subsidiaries have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish results of operations and may impact cash flows and financial condition.

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 333-87216 of Kentucky Power Company on Form S-3 of our reports dated March 5, 2004 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of a new accounting pronouncement in 2003), appearing in and incorporated by reference in this Annual Report on Form 10-K of Kentucky Power Company for the year ended December 31, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 10, 2004

POWER OF ATTORNEY**Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2003**

The undersigned directors of the following companies (each respectively the "Company")

<u>Company</u>	<u>State of Incorporation</u>
AEP Generating Company	Ohio
Appalachian Power Company	Virginia
AEP Texas Central Company	Texas
AEP Texas North Company	Texas
Columbus Southern Power Company	Ohio
Kentucky Power Company	Kentucky
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint MICHAEL G. MORRIS, STEPHEN P. SMITH and SUSAN TOMASKY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2003, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have signed these presents this 28th day of January, 2004.

/s/ Jeffrey D. Cross
Jeffrey D. Cross

/s/ Armando A. Pena
Armando A. Pena

/s/ Henry W. Fayne
Henry W. Fayne

/s/ Robert P. Powers
Robert P. Powers

/s/ Thomas M. Hagan
Thomas M. Hagan

/s/ Thomas V. Shockley, III
Thomas V. Shockley, III

/s/ Michael G. Morris
Michael G. Morris

/s/ Susan Tomasky
Susan Tomasky

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of:

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;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15f and 15d-f), for the registrant and we have:
- a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and
 - c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
- a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2004

By: /s/ Michael G. Morris

Chief Executive Officer

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:

1. I have reviewed this annual report on Form 10-K of:

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;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15f and 15d-f), for the registrant and we have:
 - a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and
 - c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
 - a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2004

By: /s/ Susan Tomasky

Chief Financial Officer

This Certificate is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the "reports") for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof, I, Michael G. Morris, the chief executive officer of

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

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Michael G. Morris
Michael G. Morris

March 10, 2004

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

This Certificate is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the "reports") for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof, I, Susan Tomasky, the chief financial officer of

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

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky
Susan Tomasky

March 10, 2004

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.