UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended MARCH 31, 2004
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ----- to -----

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Sections 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 X No

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X 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 Exchange Act).

Yes No X

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 H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of Shares of Common Stock Outstanding of the Registrants at April 30, 2004	Par Value at April 30, 2004
AEP Generating Company	1,000	$1,000
AEP Texas Central Company	2,211,678	25
AEP Texas North Company	5,488,560	25
American Electric Power Company, Inc.	395,648,498	6.50
Appalachian Power Company	13,499,500	-
Columbus Southern Power Company	16,410,426	

		-
Indiana Michigan Power Company	1,400,000	-
Kentucky Power Company	1,009,000	50
Ohio Power Company	27,952,473	-
Public Service Company of Oklahoma	9,013,000	15
Southwestern Electric Power Company	7,536,640	18

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2004

This combined Form 10-Q is separately filed by 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 and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
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.
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 Pool generation and resultant wholesale system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
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.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.

GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, an AEP subsidiary.
ME SWEPCo	Mutual Energy SWEPCo L.P., a Texas retail electric provider.
Money Pool	AEP System's Money Pool.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	The Public Utility Commission of Texas.
PURPA	The Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
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, Accounting for the Effects of Certain Types of Regulation.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central Company, an AEP electric utility subsidiary.
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.
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:

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

o The performance of AEP's pension plan.
o Prices for power that AEP generates and sells at wholesale.
o Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

RESULTS OF OPERATIONS

AEP's principal operating business segments and their major activities are:
o Utility Operations:
o Domestic generation of electricity for sale to retail and wholesale customers
o Domestic electricity transmission and distribution
o Investments-Gas Operations:*
o Gas pipeline and storage services
o Investments-UK Operations:**
o International generation of electricity for sale to wholesale customers
o Coal procurement and transportation to AEP plants and third parties
o Investments-Other:
o 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.

For information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations", including "Business Strategy", in our 2003 Annual Report.

American Electric Power Company's consolidated Net Income for the three months ended March 31, 2004 and 2003 were as follows (Earnings and Average Shares Outstanding in millions):

	2004		2003	
	Earnings	EPS	Earnings	EPS
Utility Operations	$299	$0.76	$306	$0.86
Investments - Gas Operations	(10)	(0.03)	(18)	(0.05)
Investments - UK Operations	-	-	-	-
Investments - Other	11	0.03	20	0.05
All Other*	(9)	(0.02)	(15)	(0.04)
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	291	0.74	293	0.82
Investments - Gas Operations	(1)	-	3	0.01
Investments - UK Operations	(12)	(0.04)	(40)	(0.11)
Investments - Other	-	-	(9)	(0.02)
Discontinued Operations	(13)	(0.04)	(46)	(0.12)
Utility Operations	-	-	236	0.67
Investments - Gas Operations	-	-	(22)	(0.07)
Investments - UK Operations	-	-	(21)	(0.06)
Cumulative Effect of Accounting Changes	-	-	193	0.54
Total Net Income	$278	$0.70	$440	$1.24
Average Shares Outstanding		395		356

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

First Quarter 2004 Compared to First Quarter 2003

Income Before Discontinued Operations and Cumulative Effect of Accounting Changes decreased $2 million to $291 million in 2004 compared to 2003. Net Income for 2004 of $278 million or $0.70 per share includes a loss, net of taxes, on discontinued operations of $13 million. Net Income for 2003 of $440 million or $1.24 per share includes a loss, net of taxes, from discontinued operations of $46 million and a favorable impact of $193 million, net of tax, from implementing accounting pronouncements related to risk management contracts and asset retirement obligations.

During the fourth quarter of 2003 we concluded that the UK Operations and LIG were not part of our core business, and we began actively marketing each of these investments for sale. The UK Operations consist of our generation and trading operations that sell to wholesale customers and our coal procurement and transportation operations. We continue to seek buyers for our UK Operations. LIG's operations include 2,000 miles of intrastate gas pipelines, gas processing facilities and a 9 billion cubic feet natural gas storage facility. The pipeline and processing operations of LIG were sold in April 2004 (see Note 7).

Average shares outstanding increased to 395 million in 2004 from 356 million in 2003 due to a common stock issuance in March 2003. The additional average shares outstanding decreased our 2004 earnings per share by $0.08.

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

Utility Operations

Summary of Selected Sales Data For Utility Operations For the Three Months Ended March 31, 2004 and 2003

	2004	2003
Energy Summary	(in millions of KWH)	
Retail		
Residential	13,442	13,513
Commercial	8,827	8,891
Industrial	12,434	12,612
Miscellaneous	743	695
Total	35,446	35,711
Wholesale	19,341	20,359

	2004	2003
Weather Summary	(in degree days)	
Eastern Region		
Actual - Heating	1,864	2,028
Normal - Heating*	1,806	**
Actual - Cooling	3	1
Normal - Cooling*	3	**
Western Region		
Actual - Heating	553	684
Normal - Heating*	634	**
Actual - Cooling	56	24
Normal - Cooling*	49	**

*Normal Heating/Cooling represents the 30-year average of degree days. **Not meaningful.

First Quarter 2004 Compared to First Quarter 2003

Income from Utility Operations, before the 2003 $236 million cumulative effect of accounting changes, decreased $7 million to $299 million in 2004. A $32 million increase in gross margins and a $12 million decrease in other expenses offset a $51 million increase in operations and maintenance expense.

Our gross margin, defined as utility revenues net of related fuel and purchased power, increased as follows:

o Residential demand decreased slightly over the prior year as a consequence of milder weather, while slightly lower commercial and industrial demand resulted from the continued slow economic recovery in our regions. Our reduced demand was offset by increases in fuel recoveries, coming from lower 2004 fuel disallowances in Texas when compared to 2003. The net impact of lower demand and higher fuel recoveries was a slightly improved retail energy contribution to earnings.
o Beginning in 2004, we no longer recognize revenues for excess cost over market-based stranded costs, resulting in $56 million of lower regulatory deferrals for excess cost over market-based stranded costs which reduced earnings. For the years 2003 and 2002, we recognized the non-cash provisions for stranded cost recovery in Texas as a regulatory asset 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.
o Margins from off-system sales for 2004 were $50 million better than in 2003 due to favorable power and coal optimization activity.

Utility operating expenses increased as follows:

o Maintenance and Other Operation expense increased $51 million due to the timing of tree trimming activity and planned plant outages in 2004 compared to 2003. These increases were offset, in part, by the changes in accounting treatment for our Gavin Scrubber Leases.
o Depreciation and Amortization expense increased $15 million due, in part, to the change in our accounting treatment for Gavin Scrubber Leases when we adopted the provisions of a new accounting interpretation (FIN 46) in the second half of 2003. The accounting change caused similar offsetting decreases in Maintenance and Other Operation expenses.

Investments - Gas Operations

First Quarter 2004 Compared to First Quarter 2003

Our $10 million loss from our Gas Operations before discontinued operations and cumulative effect of accounting changes compares with an $18 million loss recorded in the first quarter of 2003. Gross margins improved year-over-year, excluding the effect of one time accounting adjustments, and operating expenses have decreased as a result of the reduction in our trading activities.

Investments - UK Operations

First Quarter 2004 Compared to First Quarter 2003

Our UK Operations (all classified as Discontinued Operations) incurred a loss of $12 million for 2004 compared with a loss of $40 million in 2003, before the cumulative effect of accounting changes. During late 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 impaired certain U.K. investments in the fourth quarter of 2003 based on bids received from interested buyers.

Our UK Operations gross margins from generation increased $45 million in 2004, reflecting the improvement in wholesale electricity prices in the U.K. but were offset by a $49 million increase in losses from coal and freight contracts. These losses resulted from adverse price movements during the quarter. The decrease in the overall UK Operations loss was driven by an $8 million decrease in trading expenses, a $5 million decrease in depreciation from the cessation of plant depreciation, a $12 million decrease in interest expense and a $7 million decrease in tax expense.

Investments - Other

First Quarter 2004 Compared to First Quarter 2003

Income before discontinued operations and cumulative effect of accounting changes from our Other Investments segment decreased by $9 million to $11 million in 2004. The decrease was primarily due to a $26 million nonrecurring gain from the sale of Mutual Energy recorded in 2003. This was offset by a $4 million increase in results at AEP Coal and an increase in income in our independent power producer and wind farm investments. The majority of the AEP Coal assets were sold in April 2004 (see Note 7).

All Other

Our parent company's 2004 expenses decreased $6 million over 2003 primarily from lower interest costs due to decreased debt at the parent level and reduced reliance on short-term borrowings.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

Capitalization	March, 31 2004	December 31, 2003
Common Equity	36.2%	35.1%
Preferred Stock	0.6	0.6
Long-term Debt, including amounts due within one year	61.7	62.8
Short-term Debt	1.5	1.5
Total Capitalization	100.0%	100.0%

In addition to the impact of our $901 million in cash flows from operations and a reduction in dividends paid, we reduced long-term debt by $334 million. We also improved our percentage of common equity outstanding to total capitalization, in part through the issuance of $10 million of new common equity. As a consequence of the capital changes during the quarter, we improved our ratio of debt to total capital.

In April 2004, we retired approximately $76.2 million of long-term debt using the net cash proceeds from the sale of LIG Pipeline assets.

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, at March 31, 2004, of approximately $3.6 billion as illustrated in the table below.

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit (a)	$ 750	May 2004
Lines of Credit	1,000	May 2005
Lines of Credit	750	May 2006
Euro Revolving Credit Facility	183	October 2004
Letter of Credit Facility	200	September 2006
Total	2,883	
Available Cash and Temporary Investments	1,071 (b)	
Total Liquidity Sources	3,954	
Less: AEP Commercial Paper Outstanding	284 (c)	
Letters of Credit Outstanding	101	
Net Available Liquidity at March 31, 2004	$3,569	

(a) In early May 2004, we renewed the existing $750 million line of credit expiring in May 2004 as a 3 year, $1 billion facility.
(b) Available Cash and Temporary Investments of $1,071 million and $182 million of other cash on hand make up the $1,253 million Cash and Cash Equivalents balance on our Consolidated Balance Sheet at March 31, 2004.
(c) Amount does not include JMG Funding LP commercial paper outstanding in the amount of $27 million. This commercial paper is specifically associated with the Gavin scrubber lease and 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 March 31, 2004, this percentage was 57.6%. Non-performance of these covenants may result in an event of default under these credit agreements. At March 31, 2004, we were in compliance with the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or certain obligations 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 our utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts us and our utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization.

Credit Ratings

We continue to take steps to improve our credit quality, including plans during 2004 to further reduce our outstanding debt through the use of proceeds from our planned dispositions. If we receive a downgrade in our credit ratings by one of the nationally recognized rating agencies listed below, our borrowing costs would increase. The rating agencies currently have AEP and our rated subsidiaries on stable outlook. Current ratings for AEP are as follows:

	Moody's	S&P	Fitch
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.

	Three Months Ended March 31, 2004	2003
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$1,182	$1,199
Net Cash Flows From Operating Activities	901	762
Net Cash Flows Used For Investing Activities	(254)	(1,001)
Net Cash Flows From (Used For) Financing Activities	(576)	754
Net Increase in Cash and Cash Equivalents	71	515
Cash and Cash Equivalents at End of Period	$1,253	$1,714

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provide necessary working capital and help us 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.

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

Three Months Ended March 31,	2004	2003
	(in millions)	
Net Income	$278	$440
Plus: Discontinued Operations	13	46
Income from Continuing Operations	291	486
Noncash Items Included in Earnings	208	73
Changes in Assets and Liabilities	402	203
Net Cash Flows From Operating Activities	$901	$762

2004 Operating Cash Flow

Our cash flows from operating activities were $901 million for the first quarter 2004. We produced income from continuing operations of $291 million during the period. Income from continuing operations for the period included noncash expense items of $267 million for depreciation, amortization and deferred taxes. In addition, there is a current period impact for a net $59 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. The other 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 changes in accounts receivable and accounts payable of $83 million, and an increase in the balance of accrued taxes of $189 million.

2003 Operating Cash Flow

Income from continuing operations was $486 million for the first quarter of 2003. Income from continuing operations for the period included noncash items of $247 million for depreciation, amortization, and deferred taxes, and $193 million related to the cumulative effect of an accounting change. There was a current period impact for a net $19 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 other activity in the asset and liability accounts related to the wholesale capacity auction true-up asset (ECOM) of $56 million, deposits associated with risk management activities of $201 million, and seasonal increases in accrued taxes of $206 million.

Investing Activities

Three Months Ended March 31,	2004	2003
	(in millions)	
Construction Expenditures	$(309)	$(292)
Investment in Discontinued Operations, net	7	(749)
Proceeds from Sale of Assets	40	35

Other	8	5
Net Cash Flows Used for Investing Activities	$(254)	$(1,001)

Our cash flows used for investing activities decreased $747 million from the same period in the prior year primarily due to investments made in our U.K. operations during the first quarter of 2003 that did not recur during the first quarter of 2004.

Financing Activities

	Three Months Ended March 31,	
	2004	2003
	(in millions)	
Issuances of Common Stock	$10	$1,143
Issuances/Retirements of Debt, net	(444)	(186)
Retirement of Preferred Stock	(4)	-
Dividends	(138)	(203)
Net Cash Flows From (Used for) Financing Activities	$(576)	$754

Our cash flow for financing activities in 2004 decreased $1.3 billion from the $754 million net cash inflow recorded in the first quarter of 2003. During the first quarter of 2003 we issued $1,143 million of common stock and subsequent to the first quarter of 2003, we reduced our dividend. This compares to only $10 million of cash proceeds from the issuance of common in the first quarter of 2004.

During the first three months of 2004, we retired approximately $414 million of long-term debt, excluding $25 million related to an asset sale, and decreased our short-term debt by $103 million. We also issued approximately $73 million of long-term debt including $54 million of pollution control bonds (installment purchase contracts) at SWEPCo. These activities were supported by the generation of $901 million in cash flow from operations. See Note 10 "Financing Activities" for further information regarding issuances and retirements of debt instruments during the first quarter of 2004.

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. Our off-balance sheet arrangements have not changed significantly from year-end 2003 and are comprised of a sale of receivables agreement maintained by AEP Credit, a sale and leaseback transaction entered into by AEGCo and I&M with an unrelated unconsolidated trustee, and an agreement with an unrelated, unconsolidated leasing company to lease coal-transporting aluminum railcars. Our current plans limit the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that are entered into in the normal course of business. For complete information on each of these off-balance sheet arrangements see the "Minority Interest and Off-balance Sheet Arrangements" in "Management's Financial Discussion and Analysis of Results of Operations" section of the 2003 Annual Report.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, own 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. Commercial operation of the Facility as required by the agreements between Juniper, AEP and The Dow Chemical Company (Dow) was achieved on March 18, 2004. The initial term of the lease commenced on March 18, 2004, and we may extend the lease term for up to 30 years. The lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on AEP's balance sheet.

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.

At March 31, 2004, Juniper's acquisition costs for the Facility totaled $516 million, and we estimate total costs for the completed Facility to be approximately $525 million. For the 30-year extended lease term, the majority of base lease rental is a variable rate obligation indexed to three-month LIBOR (1.11% as of March 31, 2004). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. 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. At March 31, 2004 and December 31, 2003, we reflected $396 million 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 $516 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. Commercial operation for purposes of the PPA began April 2, 2004.

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 and 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 argued that in the absence of mutually agreed upon protocols there were 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.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursuing against TEM and Tractebel SA under the guaranty damages and the full termination payment value of the PPA.

SIGNIFICANT FACTORS

Progress Made on Announced Divestitures

We are continuing with our announced plan 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 and certain independent power producers (IPPs).

Pushan Power Plant

In December 2003, we signed an agreement to sell our interest in the Pushan Power Plant in Nanyang, China to our minority interest partner. The sale was completed in March 2004 and the effect of the sale on our first quarter results of operations was not significant.

Texas Generation

We made progress on our planned divestiture of certain Texas generation assets by (1) announcing in January 2004 that we had signed an agreement to sell TCC's
7.8% share of the Oklaunion Power Station for approximately $43 million, subject to closing adjustments, (2) announcing in February 2004 that we had signed an agreement to sell TCC's 25.2% share of the South Texas Project nuclear plant for approximately $333 million, subject to closing adjustments, and (3) announcing in March 2004 that we had signed an agreement to sell TCC's remaining generating assets, including eight natural gas plants, one coal-fired plant and one hydro plant for approximately $430 million, subject to closing adjustments. Subject to certain co-owners' rights of first refusal, we expect all of our announced sales to close before the end of 2004, after receiving appropriate regulatory approvals and clearances. We will file with the Public Utility Commission of Texas to recover net stranded costs associated with each of the sales pursuant to Texas restructuring legislation.

AEP Coal

In 2003, as a result of management's decision to exit our non-core business, we retained an advisor to facilitate the sale of AEP Coal. In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal. The sale closed in April 2004 and the effect of the sale on second quarter of 2004 results of operations should not be significant.

Gas Operations

During the third quarter of 2003, management hired advisors to review business options regarding various investment components of our Investments-Gas Operations segment. We continue to evaluate the merits of retaining our interest in Houston Pipe Line, which is part of our Investments-Gas Operations segment. In February 2004, we signed an agreement to sell the pipeline assets of LIG. The sale was completed in early April 2004 and the impact on results of operations in the second quarter of 2004 is not expected to be significant. We continue to market the remaining LIG gas storage assets.

IPP Investments

During the third quarter of 2003, we initiated an effort to sell four domestic IPP investments. In accordance with accounting principles generally accepted in the United States of America, we were required to measure the impairment of each of these four investments individually. Based on studies using market assumptions, which indicated that two of the facilities had declines in fair value that were other than temporary in nature, we recorded an impairment of $70 million pre-tax ($45.5 million net of tax) in the third quarter of 2003. During the fourth quarter of 2003, we distributed an information memorandum related to the planned sale of our interest in these IPPs. In March 2004, we entered into an agreement to sell the four IPP investments for a sales price of $156 million, subject to closing adjustments. We expect the transaction will result in a pre-tax gain of approximately $100 million (primarily related to the two facilities in Florida which were not impaired) when the sale is expected to close later in 2004.

UK Operations

During the fourth quarter of 2003, we engaged an advisor for the disposition of our U.K business. 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. We continue to work towards identifying a buyer for these assets and plan to dispose of them during 2004.

Other

We continue 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 believe our non-core assets are stated at fair value. However, we may realize losses from operations or losses upon disposition of these assets that, in the aggregate, could have a material impact on our results of operations, cash flows and financial condition.

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. In addition, legislation in some of our states requires RTO participation.

The status of the transfer of functional control of our subsidiaries' transmission systems to RTOs or the status of our participation in RTOs has not changed significantly from our disclosure as described in "RTO Formation" within the "Management's Financial Discussion and Analysis of Results of Operations" section of the 2003 Annual Report.

In November 2003, the FERC preliminarily found that we must fulfill our CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. FERC based their order on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. An ALJ held hearings on issues including whether the laws, rules, or regulations of Virginia and Kentucky prevent us from joining an RTO and whether the exceptions under PURPA 205(a) apply. The FERC ALJ affirmed the FERC's preliminary findings in March 2004. The FERC has not issued a final order in this matter.

In April 2004, we reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC is expected to consider the settlement agreement in May 2004.

Litigation

We continue to be involved in various litigation matters as described in the "Significant Factors - Litigation" section of Management's Financial Discussion and Analysis of Results of Operations in our 2003 Annual Report. The 2003 Annual Report should be read in conjunction with this report in order to understand other litigation matters that did not have significant changes in status since the issuance of our 2003 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition. Other matters described in the 2003 Annual Report that did not have significant changes during the first quarter of 2004, that should be read in order to gain a full understanding of our current litigation include: (1) Bank of Montreal Claim, (2) Shareholders' Litigation, (3) Cornerstone Lawsuit, and (4) Texas Commercial Energy, LLP Lawsuit.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation within "Significant Factors - Environmental Matters."

Enron Bankruptcy

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

Bammel storage facility and HPL indemnification matters - In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipelines pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years.

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we will acquire title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million. AEP and Enron will mutually release each other from all claims associated with the Bammel facility, including our indemnity claims. The proposed settlement is subject to Bankruptcy Court approval. The parties respective trading claims and Bank of America's (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (10.5 BCF and 55 BCF as described in the preceeding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. At the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in 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 reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. 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 filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit.

In February 2004, Enron, in connection with BOA's dispute, filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted 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 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.

Enron bankruptcy summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Management is unable to predict the outcome of this lawsuit or its impact on our 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.

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 whether these governmental agencies will take further action with respect to these matters.

TEM Litigation

See discussion of TEM litigation within the "Power Generation Facility" section of "Financial Condition - Other" within Management's Financial Discussion and Analysis of Results of Operations.

Environmental Matters

As discussed in our 2003 Annual Report, there are new environmental control requirements that we expect will result in substantial capital investments and operational costs through 2010. The sources of these future requirements include:

o Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
o New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
o Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

This discussion updates certain events occurring in 2004 and adds an estimate of future capital expenditures for the Clean Water Act rule. You should also read the "Significant Factors - Environmental Matters" section within Management's Financial Discussion and

Analysis of Results of Operations in our 2003 Annual Report for a complete description of all material environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) superfund and state remediation, (4) global climate change, and (5) costs for spent nuclear fuel and decommissioning.

Future Reduction Requirements for SO2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent national ambient air quality standards 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 finalized designations for ozone non-attainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in state implementation plans (SIPs) to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of non-attainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA identified SO2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO2 from our generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Regulatory Emissions Reductions

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

o The Federal EPA proposed an interstate air quality rule for reducing SO2 and NOx 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 national ambient air quality standards. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
o 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 NOx and SO2 emissions from coal-fired electric utility units. SO2 and NOx 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 NOx 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 NOx trading programs have not yet been proposed.

On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include "Best Available Retrofit" requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative "Best Available Retrofit" program based on emissions budgeting and trading programs. For utility units that are affected by the January 24, 2004 Interstate Air Quality Rule (IAQR), described above, the Federal EPA proposed that participation in the trading program under the IAQR would satisfy any applicable "Best Available Retrofit" requirements.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of maximum achievable control technology (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 NOx (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 NOx 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, which can be used to comply with the more stringent SO2 and NOx 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. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register on March 16, 2004. Comments on both the initial proposal and the supplemental notice are due on or before June 29, 2004.

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, NOx 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.

New Source Review Litigation

Under the Clean Air Act (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 new source review requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications 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.

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, once-through cooled 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. All plants must reduce fish mortality by 80% to 95%. 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. These plants must reduce the rate of smaller organisms passing through the plant by 60% to 90%. 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. The capital cost of compliance for our facilities, based on the Federal EPA's estimates in the rule, is $193 million. Any capital costs associated with compliance activities to meet the new performance standards would likely be incurred during the years 2008 through 2010. We have not independently confirmed the accuracy of the Federal EPA's estimate. The rule has provisions to limit compliance costs. We may propose less costly site-specific performance criteria if our compliance cost estimates are significantly greater than the Federal EPA's estimates or greater than the environmental benefits. The rule also allows us to propose mitigation (also called restoration measures) that is less costly and has equivalent or superior environmental benefits than meeting the criteria in whole or in part.

Critical Accounting Policies

See "Critical Accounting Policies" in "Management's Financial Discussion and Analysis of Results of Operations" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

Other Matters

As discussed in our 2003 Annual Report, there are several "Other Matters" affecting us, including FERC's proposed standard market design and FERC's market power mitigation efforts. These were no significant changes to the status of FERC's proposed standard market design. The current status of FERC's market power mitigation efforts is described below.

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. In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. AEP and two unaffiliated utilities were required to submit generation market power analyses within sixty days of the FERC's order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. Management is unable to predict the outcome of these actions by the FERC or their affect on future results of operations and cash flows.

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)
Three Months Ended March 31, 2004

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2003	$286	$5	$(246)	$45
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(34)	23	149	138
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	-	-
Net Option Premiums Paid/(Received) (c)	12	18	2	32
Change in Fair Value Due to Valuation Methodology Changes	-	-	-	-
Changes in Fair Value of Risk Management Contracts (d)	51	(20)	(26)	5
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(1)	-	-	(1)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2004	$314	$26	$(121)	219
Net Cash Flow Hedge Contracts (f)				(103)
Net Risk Management Liabilities Held for Sale, included in the totals above (g)				178
Ending Net Risk Management Assets at March 31, 2004				$294

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 and were entered into prior to 2004.
(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 2004. 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 2004.
(d) "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.
(e) "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.
(f) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed in detail within the following pages.
(g) See Note 7 for discussion of Assets Held for Sale.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of March 31, 2004

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Current Assets	$568	$267	$297	$1,132
Non Current Assets	398	174	120	692
Total Assets	$966	$441	$417	$1,824
Current Liabilities	$(449)	$(232)	$(404)	$(1,085)
Non Current Liabilities	(203)	(183)	(134)	(520)
Total Liabilities	$(652)	$(415)	$(538)	$(1,605)
Total Net Assets (Liabilities), excluding Cash Flow Hedges	$314	$26	$(121)	$219

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of March 31, 2004

	Risk Management Contracts*	Cash Flow Hedges	Assets Held for Sale	Consolidated
		(in millions)		
Current Assets	$1,132	$25	$(297)	$860
Non Current Assets	692	1	(120)	573
Total Assets	$1,824	$26	$(417)	$1,433
Current Liabilities	$(1,085)	$(116)	$461	$(740)
Non Current Liabilities	(520)	(13)	134	(399)
Total Liabilities	$(1,605)	$(129)	$595	$(1,139)
Total Net Assets (Liabilities)	$219	$(103)	$178	$294

*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.

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in millions)			
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$(22)	$(13)	$(1)	$3	$-	$-	$(33)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	102	74	22	7	4	-	209
Prices Based on Models and Other Valuation Methods (b)	11	20	14	26	23	44	138
Total	$91	$81	$35	$36	$27	$44	$314
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$60	$29	$(1)	$1	$-	$-	$89
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(17)	13	-	-	-	-	(4)
Prices Based on Models and Other Valuation Methods (b)	-	(38)	(9)	(3)	(3)	(6)	(59)
Total	$43	$4	$(10)	$(2)	$(3)	$(6)	$26
Investments - UK Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$-	$-	$-	$-	$-	$-	$-
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(38)	(82)	(1)	-	-	-	(121)
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$(38)	$(82)	$(1)	$-	$-	$-	$(121)
Consolidated:							
Prices Actively Quoted - Exchange Traded Contracts	$38	$16	$(2)	$4	$-	$-	$56
Prices Provided by Other External Sources - OTC Broker Quotes (a)	47	5	21	7	4	-	84
Prices Based on Models and Other Valuation Methods (b)	11	(18)	5	23	20	38	79
Total	$96	$3	$24	$34	$24	$38	$219

(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) 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 March 31, 2004

Domestic	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX Henry Hub	69
	Physical Forwards	Gulf Coast, Texas	12
	Swaps	Gas East - Northeast, Mid-continent Gulf Coast, Texas	12
	Swaps	Gas West - Rocky Mountains, West Coast	12
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	PJM	33
	Physical Forwards	Cinergy	33
	Physical Forwards	PJM	33
	Physical Forwards	NYPP	33
	Physical Forwards	NEPOOL	21
	Physical Forwards	ERCOT	21
	Physical Forwards	TVA	-
	Physical Forwards	Com Ed	21
	Physical Forwards	Entergy	21
	Physical Forwards	PV, NP15, SP15, MidC, Mead	57
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	33
Emissions	Credits	SO2	21
Coal	Physical Forwards	PRB, NYMEX, CSX	33
International			
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) (AOCI) on the Balance Sheet

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

We employ 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 tables below provide detail on effective cash flow hedges under SFAS 133 included in our balance sheet. The data in the first table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. This table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2003 to March 31, 2004.

Information on energy merchant activities is presented separately from interest rate, foreign currency risk management activities and other hedging activities. In accordance with accounting principles generally accepted in the United States of America, 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 March 31, 2004

Portion Expected
to

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	be Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power and Gas	$(42)	$(36)
Foreign Currency	(18)	(18)
Interest Rate	(12)	(5)
Total	$(72)	$(59)

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2004

	Power and Gas	Foreign Currency	Interest Rate	Consolidated
	(in millions)			
Beginning Balance, December 31, 2003	$(65)	$(20)	$(9)	$(94)
Changes in Fair Value (c)	(30)	(6)	(4)	(40)
Reclassifications from AOCI to Net Income (d)	53	8	1	62
Ending Balance, March 31, 2004	$(42)	$(18)	$(12)	$(72)

(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. Except for one counterparty who has a net exposure of approximately $45 million, we believe that credit exposure with any one counterparty is not material to our financial condition at March 31, 2004. At March 31, 2004, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 20% expressed in terms of net MTM assets and net receivables. The increase in non-investment grade credit quality was largely due to an increase to coal exposures related to domestic MTM coal transactions and coal and freight exposures related to our U.K. investments. These increases were driven by the continued high levels of prices for coal and freight. As of March 31, 2004, 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	Number of Counterparties > 10%	Net Exposure of Counterparties > 10%
	(in millions, except number of counterparties)				
Investment Grade	$912	$102	$810	-	$-
Split Rating	24	-	24	3	18
Non-Investment Grade	364	199	165	4	117
No External Ratings:					
Internal Investment Grade	319	5	314	2	115
Internal Non-Investment Grade	160	41	119	3	100
Total	$1,779	$347	$1,432	12	$350

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 March 31, 2004

	Remainder 2004	2005	2006
Estimated Plant Output Hedged	88%	91%	91%

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 March 31, 2004, 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

Three Months Ended March 31, 2004 (in millions)				Twelve Months Ended December 31, 2003 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$19	$10	$2	$11	$19	$7	$4

The 2004 first quarter High VaR was due to the wind-down of the London risk management activities. These activities were concluded by the end of the quarter.

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

CCRO VaR Metrics

	March 31, 2004	Average for Year-to-Date 2004	High for Year-to-Date 2004	Low for Year-to-Date 2004
	(in millions)			
95% Confidence Level, Ten-Day Holding Period	$9	$38	$73	$8
99% Confidence Level, One-Day Holding Period	$4	$16	$30	$3

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 $0.843 billion at March 31, 2004 and $1.013 billion at December 31, 2003. 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 Indiana, 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 Three Months Ended March 31, 2004 and 2003
(in millions, except per-share amounts)
(Unaudited)

	2004	2003
REVENUES		
Utility Operations	$2,579	$2,687
Gas Operations	652	933
Other	110	165
TOTAL	3,341	3,785
EXPENSES		
Fuel for Electric Generation	688	730
Purchased Electricity for Resale	83	156
Purchased Gas for Resale	585	878
Maintenance and Other Operation	876	894
Depreciation and Amortization	317	309
Taxes Other Than Income Taxes	184	188
TOTAL	2,733	3,155
OPERATING INCOME	608	630
Other Income (Expense), Net	49	66
INTEREST AND OTHER CAPITAL CHARGES		
Interest	199	192
Preferred Stock Dividend Requirements of Subsidiaries	2	3
Minority Interest in Finance Subsidiary	-	9
TOTAL	201	204
INCOME BEFORE INCOME TAXES	456	492
Income Taxes	165	199
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	291	293
DISCONTINUED OPERATIONS (Net of Tax)	(13)	(46)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)		
Accounting for Risk Management Contracts	-	(49)
Asset Retirement Obligations	-	242
NET INCOME	$278	$440
AVERAGE NUMBER OF SHARES OUTSTANDING	395	356
EARNINGS PER SHARE		
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$0.74	$0.82
Discontinued Operations	(0.04)	(0.12)
Cumulative Effect of Accounting Changes	-	0.54
TOTAL EARNINGS PER SHARE (BASIC AND DILUTED)	$0.70	$1.24
CASH DIVIDENDS PAID PER SHARE	$0.35	$0.60

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$1,253	$1,182
Accounts Receivable:		
Customers	1,101	1,155
Accrued Unbilled Revenues	473	596
Miscellaneous	76	83
Allowance for Uncollectible Accounts	(129)	(124)
Total Receivables	1,521	1,710
Fuel, Materials and Supplies	961	991
Risk Management Assets	860	766
Margin Deposits	93	119
Other	142	129
TOTAL	4,830	4,897
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,389	15,112
Transmission	6,198	6,130
Distribution	9,991	9,902
Other (including gas, coal mining and nuclear fuel)	3,599	3,584
Construction Work in Progress	1,047	1,305
TOTAL	36,224	36,033
Less: Accumulated Depreciation and Amortization	14,169	14,004
TOTAL-NET	22,055	22,029
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,549	3,548
Securitized Transition Assets	679	689
Spent Nuclear Fuel and Decommissioning Trusts	1,036	982
Investments in Power and Distribution Projects	216	212
Goodwill	78	78
Long-term Risk Management Assets	573	494
Other	832	733
TOTAL	6,963	6,736
Assets Held for Sale	2,387	2,916
Assets of Discontinued Operations	-	166
TOTAL ASSETS	$36,235	$36,744

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,246	$1,337
Short-term Debt	326	326
Long-term Debt Due Within One Year*	1,904	1,779
Risk Management Liabilities	740	631
Accrued Taxes	811	620
Accrued Interest	197	207
Customer Deposits	422	379
Other	666	703
TOTAL	6,312	5,982
NON-CURRENT LIABILITIES		
Long-term Debt*	11,863	12,322
Long-term Risk Management Liabilities	399	335
Deferred Income Taxes	4,057	3,957
Regulatory Liabilities and Deferred Investment Tax Credits	2,333	2,259
Asset Retirement Obligations and Nuclear Decommissioning Trusts	664	640
Employee Benefits and Pension Obligations	691	667
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	173	176
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	72	76
Deferred Credits and Other	498	519
TOTAL	20,750	20,951
Liabilities Held for Sale	1,041	1,773
Liabilities of Discontinued Operations	-	103
TOTAL LIABILITIES	28,103	28,809
Cumulative Preferred Stocks of Subsidiaries not Subject to Mandatory Redemption	61	61
Commitments and Contingencies		
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value $6.50:		

	2004	2003
Shares Authorized.	600,000,000	600,000,000
Shares Issued.	404,643,133	404,016,413

	2004	2003
(8,999,992 shares were held in treasury at March 31, 2004 and December 31, 2003)	2,630	2,626
Paid-in Capital	4,190	4,184
Retained Earnings	1,630	1,490
Accumulated Other Comprehensive Income (Loss)	(379)	(426)
TOTAL	8,071	7,874
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$36,235	$36,744

* See Accompanying Schedule

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in millions)	
OPERATING ACTIVITIES		
Net Income	$278	$440
Plus: Discontinued Operations	13	46
Income from Continuing Operations	291	486
Adjustments for Noncash Items:		
Depreciation and Amortization	317	309
Deferred Income Taxes	49	22
Deferred Investment Tax Credits	(9)	(7)
Cumulative Effect of Accounting Changes	-	(193)
Amortization of Deferred Property Taxes	(90)	(87)
Amortization of Cook Plant Restart Costs	-	10
Mark-to-Market of Risk Management Contracts	(59)	19
Over/Under Fuel Recovery	15	74
Change in Other Assets	(6)	(165)
Change in Other Liabilities	84	(28)
Changes in Certain Components of Working Capital		
Accounts Receivable, net	180	(867)
Accounts Payable	(97)	869
Fuel, Materials and Supplies	29	163
Customer Deposits	43	201
Taxes Accrued	189	206
Interest Accrued	(10)	3
Other Current Assets	10	(57)
Other Current Liabilities	(35)	(196)
Net Cash Flows From Operating Activities	901	762
INVESTING ACTIVITIES		
Construction Expenditures	(309)	(292)
Investment in Discontinued Operations, net	7	(749)
Proceeds from Sale of Assets	40	35
Other	8	5
Net Cash Flows Used For Investing Activities	(254)	(1,001)
FINANCING ACTIVITIES		
Issuance of Common Stock	10	1,143
Issuance of Long-term Debt	73	2,498
Change in Short-term Debt, net	(103)	(2,467)
Retirement of Long-term Debt	(414)	(217)
Retirement of Preferred Stock	(4)	-
Dividends Paid on Common Stock	(138)	(203)
Net Cash Flows From (Used For) Financing Activities	(576)	754
Net Increase in Cash and Cash Equivalents	71	515
Cash and Cash Equivalents at Beginning of Period	1,182	1,199
Cash and Cash Equivalents at End of Period	$1,253	$1,714
Net Increase in Cash and Cash Equivalents from Discontinued Operations	$24	$59
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	13	21
Cash and Cash Equivalents from Discontinued Operations - End of Period	$37	$80

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest, net of capitalized amounts, was $200 million and $177 million in 2004 and 2003, respectively. There was no cash paid for income taxes in 2004 and 2003. Noncash acquisitions under capital leases were $3 million and $0 in 2004 and 2003.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME
For the Three Months Ended March 31, 2004 and 2003
(in millions)
(Unaudited)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	348	$2,261	$3,413	$1,999	$(609)	$7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(203)		(203)
Common Stock Expense			(35)			(35)
Other			(15)	2		(13)
TOTAL						7,990
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					13	13
Cash Flow Hedges					(22)	(22)
Securities Available for Sale					1	1
Minimum Pension Liability					15	15
NET INCOME				440		440
TOTAL COMPREHENSIVE INCOME						447
MARCH 31, 2003	404	$2,626	$4,175	$2,238	$(602)	$8,437
DECEMBER 31, 2003	404	$2,626	$4,184	$1,490	$(426)	$7,874
Issuance of Common Stock	1	4	6			10
Common Stock Dividends				(138)		(138)
TOTAL						7,746
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Foreign Currency Translation Adjustments					8	8
Cash Flow Hedges					22	22
Minimum Pension Liability					17	17
NET INCOME				278		278
TOTAL COMPREHENSIVE INCOME						325
MARCH 31, 2004	405	$2,630	$4,190	$1,630	$(379)	$8,071

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
TOTAL LONG-TERM DEBT OUTSTANDING		
First Mortgage Bonds	$835	$940
Installment Purchase Contracts	1,990	2,026
Notes Payable	1,491	1,518
Senior Unsecured Notes	7,857	7,997
Securitization Bonds	718	746
Notes Payable to Trust	331	331
Equity Unit Senior Notes	345	345
Long-term DOE Obligation (a)	227	226
Other Long-term Debt	21	21
Equity Unit Contract Adjustment Payments	16	19
Unamortized Discount (net)	(64)	(68)
TOTAL	13,767	14,101
Less Portion Due Within One Year	1,904	1,779
TOTAL LONG-TERM PORTION	$11,863	$12,322

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. I&M is the only AEP subsidiary that generated electric power with nuclear fuel prior to that date. Trust fund assets of $269 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Consolidated Balance Sheets at March 31, 2004 and December 31, 2003, respectively.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2003 Annual Report as incorporated in and filed with our 2003 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments which are necessary for a fair presentation of the results of operations for interim periods.

Other Income (Expense), Net

The following table provides the components of Other Income (Expense), Net as presented on our Consolidated Statements of Operations:

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(in millions)	
Other Income:		
Interest and Dividend Income	$6	$5
Equity Earnings	7	1
Non-operational Revenue	29	28
Gain on Sale of REPs (Mutual Energy Companies)	-	39
Other	38	37
Total Other Income	80	110
Other Expense:		
Non-operational Expenses	24	26
Other	7	18
Total Other Expense	31	44
Total Other Income (Expense), Net	$49	$66

Components of Accumulated Other Comprehensive Income (Loss)

The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	March 31, 2004	December 31, 2003
	(in millions)	

Foreign Currency Translation Adjustments	$118	$110
Unrealized Losses on Securities Available for Sale	(1)	(1)
Unrealized Losses on Cash Flow Hedges	(72)	(94)
Minimum Pension Liability	(424)	(441)
Total	$(379)	$(426)

We expect to reclassify approximately $59 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at March 31, 2004 to Net Income during the next twelve months at the time the hedged transactions affect net income. Five years approximates the maximum period over which an exposure to a variability in future cash flows is hedged. The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes.

In addition, during the first quarter 2004, we reclassified $23 million from Accumulated Other Comprehensive Income (Loss) related to minimum pension liability to regulatory assets ($35 million) and deferred income taxes ($12 million) as a result of authoritative letters issued by the FERC and the Arkansas and Louisiana commissions.

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.

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

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Coal Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2004 Including Held for Sale	$770.9	$75.4	$53.1	$899.4
Accretion Expense	13.7	1.5	0.8	16.0
Foreign Currency Translation	-	-	0.8	0.8
Asset Retirement Obligation Liability at March 31, 2004 including Held for Sale	784.6	76.9	54.7	916.2
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project	(222.8)	-	-	(222.8)
U.K. Plants	-	-	(30.0)	(30.0)
AEP Coal	-	-	(10.9)	(10.9)
Asset Retirement Obligation Liability at March 31, 2004	$561.8	$76.9	$13.8	$652.5

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

As of March 31, 2004 and December 31, 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $897 million and $845 million, respectively, of which $767 million and $720 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 $130 million and $125 million as of March 31, 2004 and December 31, 2003, respectively, was classified as Assets Held for Sale in our Consolidated Balance Sheets.

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.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

We implemented FIN 46R, "Consolidation of Variable Interest Entities," effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which 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.

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

In accordance with FASB Staff Position No. 106-1, in December 2003 we elected to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) until the FASB issues authoritative guidance on the accounting for the federal subsidy. 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 Financial Accounting Standards Board's (FASB's) standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on projects related to accounting for stock compensation, pension plans, property, plant and equipment, earnings per share calculations and related tax impacts. We also expect to see more projects as a result of the FASB's desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS As discussed in our 2003 Annual Report, our subsidiaries are involved in rate proceedings in the FERC and several state jurisdictions. The Rate Matters note within our 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending, without significant changes since year-end. The following sections discuss current activities.

TNC Fuel Reconciliations

In 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 as of the end of the reconciliation period. 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 remand 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. 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.

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 received a written order in March 2004 and increased the reserve by $1.5 million. In March 2004, various parties, including TNC, requested a rehearing of the PUCT's ruling.

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 was appealed to the Third Court of Appeals. In March 2004, the Third Court of Appeals heard oral arguments. A decision is pending.

TCC Fuel Reconciliation

In 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. 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. Based on an analysis of the ALJ's recommendations, TCC established an additional reserve of $13 million during the first quarter of 2004. The over-recovery balance and the provisions total $163 million including interest at March 31, 2004. 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 4 "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. 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 we achieve future cost savings. In April 2004, the PUCT approved the settlement.

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. The PUCT held hearings in March 2004 and is expected to issue a decision in June 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 Compliance Filing

In October 2002, SWEPCo filed with the Louisiana Public Service Commission (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. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCo's current rates should not be reduced. 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.

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 Corporation Commission of the State of Oklahoma (OCC) seeking recovery of the $44 million over an 18-month 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. An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested $8.8 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated trading margins were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and could more than offset the $44 million 2002 allocation. The intervenor and the OCC Staff also believed trading margins were allocated incorrectly. Under the intervenor's recalculation of margin allocation, PSO's amount of recoverable fuel would be decreased approximately $6.8 million for 2000 and $10.7 million for 2001. OCC Staff calculates the 2001 amount at $8.8 million. They also recommend recalculation of fuel for years subsequent to 2001 using the same methods. Hearings are scheduled to occur in June 2004. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of trading margins pursuant to the agreements is correct. 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.

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 $31 million of RTO formation and integration costs and related carrying charges through March 31, 2004. 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 plan to 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. 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. The AEP East companies are scheduled to join PJM in October 2004, although there are pending proceedings at the FERC and in Virginia and Kentucky concerning our integration into PJM. Therefore, 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 our share of 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. A hearing for this proceeding is scheduled in July 2004.

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. In April 2004, we reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC is expected to consider the agreement in May.

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 205(a) apply. The FERC ALJ affirmed the FERC's preliminary findings in March 2004. FERC has not issued a final order in this matter.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (ISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners 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.

In November 2003, the FERC adopted a new regional rate design and 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 was expected to implement a new rate design 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. Various parties raised issues with the SECA rate orders and FERC implemented settlement procedures before an ALJ.

In March 2004, the FERC approved a settlement that delays elimination of T&O rates until December 1, 2004 and provides principles and procedures for a new rate design for the RTO Footprint, to be effective on December 1, 2004. The settlement also provides that if the process does not result in the implementation of a new rate design on December 1, then the SECA rates will be implemented and will remain in effect until a new rate is implemented by the FERC. If implemented, the SECA rate would not be effective beyond March 31, 2006. The AEP East companies received approximately $157 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the new rate design 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. The Cook settlement agreement provided for the fixed rate to end in February 2004. In another agreement in connection with a planned corporate separation I&M agreed, contingent on implementing the corporate separation, to a new freeze conditionally beginning March 2004 and continuing through December 2007.

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 after March 1, 2004. Negotiations with the parties to determine a resolution of this issue are ongoing. The IURC ordered the fixed fuel adjustment charge remain in place, on an interim basis, for March and April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor for May through September 2004, subject to true-up following the resolution of issues in the corporate separation agreement. The IURC also issued an order that reopens the corporate separation docket to investigate issues related to the corporate separation agreement.

Michigan 2004 Fuel Recovery Plan

A Michigan Public Service Commission's (MPSC) 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. A public hearing of this case occurred on March 10, 2004 and a MPSC order is expected during the second half of 2004. 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 MPSC order.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in our 2003 Annual Report, we are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (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 Public Utilities Commission of Ohio (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. 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 charges on certain required expenditures. Management cannot predict whether the plan will be approved as submitted or its impact on results of operations 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 March 31, 2004, we have incurred $69 million and deferred $29 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:
o provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
o provides for an earnings test for each of the years 1999 through 2001 and;
o 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.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:
o net stranded generation plant costs and generation-related regulatory assets (stranded costs),
o a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),
o final approved deferred fuel balance,
o unrefunded accumulated excess earnings,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
o 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 generation 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 TCC's generation assets for stranded cost purposes. When completed, the sale of TCC's 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 generation 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 generation 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 hired a consultant to advise the PUCT and TCC during the sale of TCC's generation assets. TCC's sale of its generation 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 generation 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 generation plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to unaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices, expiring in May and June 2004, to the co-owners of Oklaunion and STP, respectively. TCC filed for FERC approval of the sales of the fossil and hydro plants. TCC will request approval of the STP sale from the FERC during the second quarter of 2004. We have received a notice from a co-owner of Oklaunion exercising their right of first refusal; therefore, SEC approval will be required. Approval of the sale of STP from the Nuclear Regulatory Commission is required. The completion of the sales is expected to occur in 2004, subject to the rights of first refusal and the necessary approvals required for each sale. TCC will file its 2004 true-up proceeding with the PUCT after the sale of the generation assets.

After the 2004 true-up proceeding, TCC may recover stranded costs and other true-up amounts through transmission and distribution rates as a competition transition and may seek to issue securitization revenue bonds for its stranded costs. The cost of the securitization bonds is recovered through transmission and distribution rates as a separate transition charge. We recorded an impairment of generation assets of $938 million in December 2003 as a regulatory asset (see Note 7). 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 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 auction true-up 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. TNC received a written order on March 1, 2004 that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $4.6 million. This balance will be included in TNC's 2004 true-up proceeding. Various parties, including TNC, requested rehearing of the PUCT's order.

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 3 "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. The District Court remanded to the PUCT an appeal of the same issue from the PUCT's 2001 order to be consistent with the Court of Appeals decision. 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.

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 price-to-beat (PTB) retail electric providers (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 March 31, 2004, the remaining retail clawback regulatory liability was $57 million.

Stranded Cost Recovery

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 a 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.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation which extends the transition period for electricity restructuring including capped rates through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two general rate changes and an opportunity for recovery of incremental environmental and reliability costs.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2003 Annual Report, we continue to be involved in various legal matters. The 2003 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2003 Annual Report. The material matters discussed in the 2003 Annual Report without significant changes in status since year-end include, but are not limited to, (1) nuclear matters, (2) construction commitments, (3) merger litigation, (4) shareholder lawsuits, (5) California lawsuits, (6) Cornerstone lawsuit, (7) Texas Commercial Energy, LLP lawsuit, (8) Bank of Montreal Claim, and (9) FERC proposed Standard Market Design. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2003 Annual Report.

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 new source review requirements of the Clean Air Act (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 CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 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 requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals, and the District Court denied the Federal EPA's motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that obviated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice.

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 CAA 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 CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and on May 3, 2004, that petition was denied.

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 a prospective effect, and was to 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.

OPERATIONAL

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, own 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. Commercial operation of the Facility as required by the agreements between Juniper, AEP and The Dow Chemical Company (Dow) was achieved on March 18, 2004. The initial term of the lease commenced on March 18, 2004, and we may extend the lease term for up to 30 years. The lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on AEP's balance sheet.

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.

At March 31, 2004, Juniper's acquisition costs for the Facility totaled $516 million, and we estimate total costs for the completed Facility to be approximately $525 million. For the 30-year extended lease term, the majority of base lease rental is a variable rate obligation indexed to three-month LIBOR (1.11% as of March 31, 2004). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. 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. At March 31, 2004 and December 31, 2003, we reflected $396 million 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 $516 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. Commercial operation for purposes of the PPA began April 2, 2004.

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 and 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 argued that in the absence of mutually agreed upon protocols there were 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.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursuing against TEM and Tractebel SA under the guaranty damages and the full termination payment value of the PPA.

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the bankruptcy proceeding pending in the U.S.

Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Bammel storage facility and HPL indemnification matters - In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipelines pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years.

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we will acquire title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million. AEP and Enron will mutually release each other from all claims associated with the Bammel facility, including our indemnity claims. The proposed settlement is subject to Bankruptcy Court approval. The parties respective trading claims and Bank of America's (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (10.5 BCF and 55 BCF as described in the preceeding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. At the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in 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 reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. 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 filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit.

In February 2004, Enron, in connection with BOA's dispute, filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted 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 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.

Enron bankruptcy summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement.

Management is unable to predict the outcome of this lawsuit or its impact on our 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.

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 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. In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. AEP and two unaffiliated utilities were required to submit generation market power analyses within sixty days of the FERC's order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. Management is unable to predict the outcome of these actions by the FERC or their affect on future results of operations and cash flows.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002 in accordance with FIN 45. There is no collateral held in relation to any guarantees in excess of our ownership percentages 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 March 31, 2004, the maximum future payments for all the LOCs are approximately $322 million with maturities ranging from April 2004 to January 2011. As the parent of various 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 will be released from this guarantee upon the anticipated sale of this IPP. See Note 7 regarding the sale of IPPs, of which Fort Lupton is included.

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. We will be released from this guarantee upon the anticipated sale of this IPP. See Note 7 regarding the sale of IPPs, of which Orange Cogeneration is included.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International, AEP subsidiaries, 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. We will be released from this guarantee upon the anticipated sale of this IPP. See Note 7 regarding the sale of the IPPs, of which Polk is included.

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 $51 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 March 31, 2004, 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.

As of July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

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 and during the first quarter 2004, we entered into several sale agreements. These sale agreements include indemnifications with a maximum exposure of approximately $129 million. There are no material liabilities recorded for any indemnifications entered into during 2003 or the first quarter 2004. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At March 31, 2004, the maximum potential loss for these lease agreements was approximately $29 million assuming the fair market value of the equipment is zero at the end of the lease term.

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.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option 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 March 31, 2004, 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 terms to an unaffiliated company under an operating lease. The sublessee has recently renewed for an additional year and may renew the lease for up to three more additional one-year terms.

7. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS COMPLETED DURING FIRST QUARTER 2004

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. The sale was completed on March 2, 2004 for $60.7 million. 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 at that time, and was classified in Discontinued Operations. The effect of the sale on the first quarter 2004 results of operations was not significant.

Results of operations of Pushan have been reclassified as Discontinued Operations. The assets and liabilities of Pushan were classified on our Consolidated Balance Sheets as held for sale until the sale was complete. Beginning with our first quarter 2004 financial statements, the assets and liabilities of Pushan are shown as Assets of Discontinued Operations and Liabilities of Discontinued Operations for all periods presented.

DISPOSITIONS ANNOUNCED DURING FIRST QUARTER 2004

During the first quarter of 2004 we announced the following dispositions expected to close later this year:

Texas Plants (Utility Operations segment)

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability must run" status. During 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.

During early 2004 we signed agreements to sell all of our TCC generating assets, at prices which approximate book value after considering the impairment charge described above. As a result, we do not expect these pending asset sales, described below, to have a significant effect on our future results of operations.

Oklaunion Power Station

In January 2004, we signed an agreement to sell TCC's 7.8 percent share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments. The planned sale is expected to close in June 2004, subject to the co-owners' decisions on their rights of first refusal. We have received notice from a co-owner of their decision to exercise their right of first refusal.

South Texas Project

In February 2004, we signed an agreement to sell TCC's 25.2 percent share of the South Texas Project (STP) nuclear plant for approximately $333 million, subject to closing adjustments. We expect the sale to close in the second half of 2004, subject to the co-owners' decisions on their rights of first refusal. We do not expect the sale of this asset to have a significant effect on our results of operations.

TCC Generation Assets

In March 2004 we signed an agreement to sell our remaining generating assets within TCC, including eight natural gas plants, one coal-fired plant and one hydro plant to a non-related joint venture for approximately $430 million, subject to closing adjustments. We expect the sale to close in mid-2004, subject to various regulatory approvals and clearances.

LIG Pipeline and its Subsidiaries (Investments - Gas Operations segment)

In February 2004, we signed an agreement to sell approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana and five gas processing facilities that straddle the system. The sale of these LIG Pipeline Company assets for $76.2 million was completed in April 2004. The effect of the sale is not expected to have a significant effect on our results of operations during second quarter 2004. See Louisiana Intrastate Gas (LIG) under Discontinued Operations for additional information.

Independent Power Producers (Investments - Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). In accordance with accounting principles generally accepted in the United States of America, we were required to measure the impairment of each of these four investments individually. Based on indicative bids, it was determined that an other than temporary impairment existed on two of the equity method investments located in Colorado. The $70.0 million pre-tax ($45.5 million net of tax) impairment recorded in September 2003 was the result of the measurement of fair value that was triggered by our recent decision to sell the assets. This loss of investment value was included in Investment Value Losses on our Consolidated Statements of Operations.

On March 10, 2004, we entered into an agreement to sell the four domestic IPP investments for a sales price of $156 million. We expect the transaction will result in a pre-tax gain of approximately $100 million when the sale is expected to close later in 2004. This gain will be generated primarily from the sale of the two Florida IPPs which were not impaired.

AEP Coal (Investments - Other segment)

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 March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal. AEP received approximately $8.8 million cash and the buyer assumed an additional $10.8 million in future reclamation liability. The sale closed in April 2004 and the effect of the sale on second quarter of 2004 results of operations should not be significant. 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 March 31, 2004 and December 31, 2003.

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 2004 and 2003. Results of operations of these businesses have been reclassified for the three months ended March 31, 2004 and 2003, as shown in the following table:

	Eastex	Pushan Power Plant	LIG	U.K. Generation Plants	Total
			(in millions)		
2004 Revenue	$ -	$10	$160	$41	$211
2004 Pretax Income (Loss)	-	-	(1)	(19)	(20)
2004 Income (Loss) After-Tax	-	-	(1)	(12)	(13)
2003 Revenue	31	15	203	51	300
2003 Pretax Income (Loss)	(14)	-	3	(40)	(51)
2003 Income (Loss) After-Tax	(9)	-	3	(40)	(46)

Assets and liabilities of discontinued operations have been reclassified as follows:

	Pushan Power Plant (in millions)
As of December 31, 2003	
Current Assets	$24
Property, Plant and Equipment, Net	142
Total Assets of Discontinued Operations	$166
Current Liabilities	$26
Long-term Debt	20
Deferred Credits and Other	57
Total Liabilities of Discontinued Operations	$103

Pushan Power Plant (Investments - Other segment)

See Pushan Power Plant section under Dispositions Completed During First Quarter 2004 for information regarding the sale of Pushan Power Plant.

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 of 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. The sale was completed during early April of 2004 and the impact on results of operations in the second quarter of 2004 is not expected to be significant (see LIG Pipeline and its Subsidiaries in Dispositions Announced During First Quarter 2004 for additional information). Management continues its efforts to market the remaining gas storage assets. 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.

In the fourth quarter of 2003, the U.K. generation plants were determined to be non-core assets and management engaged 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 plants. Based on information received, 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.

ASSETS HELD FOR SALE

The assets and liabilities of the entities held for sale at March 31, 2004 and December 31, 2003 are as follows:

March 31, 2004	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Total
			(in millions)		
Assets:					
Current Risk Management Assets	$297	$-	$-	$-	$297
Other Current Assets	504	9	56	51	620
Property, Plant and Equipment, Net	101	11	799	167	1,078
Regulatory Assets	-	-	48	-	48
Decommissioning Trusts	-	-	130	-	130
Goodwill	-	-	-	15	15
Long-term Risk Management Assets	120	-	-	-	120
Other	70	-	-	9	79
Total Assets Held for Sale	$1,092	$20	$1,033	$242	$2,387
Liabilities:					
Current Risk Management Liabilities	$449	$-	$-	$12	$461
Other Current Liabilities	101	-	-	48	149
Long-term Risk Management Liabilities	134	-	-	-	134
Regulatory Liabilities	-	-	9	-	9
Asset Retirement Obligations	30	11	223	-	264
Employee Benefits and Pension Obligations	12	-	-	-	12
Deferred Credits and Other	1	-	-	11	12
Total Liabilities Held for Sale	$727	$11	$232	$71	$1,041

December 31, 2003	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Total

			(in millions)		
Assets:					
Current Risk Management Assets	$560	$-	$-	$-	$560
Other Current Assets	685	6	57	50	798
Property, Plant and Equipment, Net	99	13	797	171	1,080
Regulatory Assets	-	-	49	-	49
Decommissioning Trusts	-	-	125	-	125
Goodwill	-	-	-	15	15
Long-term Risk Management Assets	274	-	-	-	274
Other	6	-	-	9	15
Total Assets Held for Sale	$1,624	$19	$1,028	$245	$2,916
Liabilities:					
Current Risk Management Liabilities	$767	$-	$-	$15	$782
Other Current Liabilities	221	-	-	46	267
Long-term Risk Management Liabilities	435	-	-	-	435
Regulatory Liabilities	-	-	9	-	9
Asset Retirement Obligations	29	11	219	-	259
Employee Benefits and Pension Obligations	12	-	-	-	12
Deferred Credits and Other	-	3	-	6	9
Total Liabilities Held for Sale	$1,464	$14	$228	$67	$1,773

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost (credit) for the following plans for the three months ended March 31, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Service Cost	$22	$20	$11	$11
Interest Cost	57	58	33	32
Expected Return on Plan Assets	(73)	(79)	(21)	(16)
Amortization of Transition (Asset) Obligation	-	(2)	7	7
Amortization of Net Actuarial Loss	4	2	12	13
Net Periodic Benefit Cost (Credit)	$10	$(1)	$42	$47

9. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations

o Domestic generation of electricity for sale to retail and wholesale customers
o Domestic electricity transmission and distribution

Investments - Gas Operations*

o Gas pipeline and storage services

Investments - UK Operations**

o International generation of electricity for sale to wholesale customers
o Coal procurement and transportation to AEP plants and third parties

Investments - Other

o 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 income statement information for the three months ended March 31, 2004 and 2003 and balance sheet information as of March 31, 2004 and December 31, 2003. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
2004			(in millions)				
Revenues from:							
External Customers	$2,579	$652	$-	$110	$-	$-	$3,341
Other Operating Segments	292	24	-	33	2	(351)	-
Discontinued Operations, Net of Tax	-	(1)	(12)	-	-	-	(13)
Net Income (Loss)	299	(11)	(12)	11	(9)	-	278
Total Assets	31,044	2,279	978	1,557	13,130	(12,753)	36,235
Assets Held for Sale and Assets of Discontinued Operations	1,033	242	1,092	20	-	-	2,387

* 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.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
2003			(in millions)				
Revenues from:							
External Customers	$2,687	$933	$-	$165	$-	$-	$3,785
Other Operating Segments	-	44	-	13	-	(57)	-
Discontinued Operations, Net of Tax	-	3	(40)	(9)	-	-	(46)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	542	(37)	(61)	11	(15)	-	440
Total Assets	30,816	2,405	1,705	1,697	14,925	(14,804)	36,744
Assets Held for Sale and Assets of Discontinued Operations	1,033	240	1,624	185	-	-	3,082

* 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.

10. FINANCING ACTIVITIES

Long-term debt and other securities issuances and retirements during the first three months of 2004 are shown in the table below. Amounts in total do not necessarily tie to our statements of cash flows due to rounding and due to retirements of debt of discontinued operations not included in the amount on our statements of cash flows.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
SWEPCo	Installment Purchase Contracts	$54	Variable	2019

Non-Registrant:				
AEP Subsidiary	Notes Payable	20	Variable	2009

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Retirements:				
APCo	Installment Purchase Contracts	$40	5.45	2019
OPCo	Installment Purchase Contracts	50	6.85	2022
OPCo	Notes Payable	2	6.27	2009
OPCo	Notes Payable	1	6.81	2008
OPCo	Senior Unsecured Notes	140	7.375	2038
SWEPCo	First Mortgage Bonds	80	6.875	2025
SWEPCo	Notes Payable	2	4.47	2011
SWEPCo	Notes Payable	1	Variable	2008
TCC	First Mortgage Bonds	1	7.125	2005
TCC	Securitization Bonds	29	3.54	2005
TNC	First Mortgage Bonds	24	6.125	2004
Non-Registrant:				
AEP Subsidiary	Notes Payable	$40	6.73	2004
AEP Subsidiaries	Notes Payable and Other Debt	29	Variable	2007-2017

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

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. 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.

First Quarter 2004 Compared to First Quarter 2003

Net Income increased $31 thousand for the first quarter of 2004 compared with the first quarter of 2003. 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 decreased $304 thousand for the first quarter of 2004 compared with the first quarter of 2003 primarily due to:

o A $5 million decrease in Operating Revenue as a result of decreased recoverable expenses, primarily Fuel for Electric Generation, in accordance with the unit power agreements along with a decreased return on total capital.
o A $4 million increase in Maintenance expense as a result of planned outages. In the first quarter of 2004, we incurred planned outages related to boiler inspections.

The decrease in Operating Income was offset by:

o A $9 million decrease in Fuel for Electric Generation expense. This decrease is primarily due to a 30% decrease in MWH generation as a result of the planned outages.

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. Our off-balance sheet arrangement has not changed significantly from year-end 2003 and is comprised of a sale and leaseback transaction entered into by AEGCo and I&M with an unrelated unconsolidated trustee. Our current plans limit the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that are entered into in the normal course of business. For complete information on this off-balance sheet arrangement see "Off-balance Sheet Arrangements" in "Management's Narrative Financial Discussion and Analysis" section of our 2003 Annual Report.

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES	$55,282	$60,428
OPERATING EXPENSES		
Fuel for Electric Generation	21,398	30,397
Rent - Rockport Plant Unit 2	17,071	17,071
Other Operation	2,490	2,549
Maintenance	5,400	1,651
Depreciation and Amortization	5,734	5,621
Taxes Other Than Income Taxes	944	791
Income Taxes	698	497
TOTAL	53,735	58,577
OPERATING INCOME	1,547	1,851
Nonoperating Income	24	2
Nonoperating Expenses	69	217
Nonoperating Income Tax Credits	857	894
Interest Charges	532	734
NET INCOME	$1,827	$1,796

STATEMENTS OF RETAINED EARNINGS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
BALANCE AT BEGINNING OF PERIOD	$21,441	$18,163
Net Income	1,827	1,796
Cash Dividends Declared	1,262	1,171
BALANCE AT END OF PERIOD	$22,006	$18,788

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
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$648,802	$645,251
General	4,117	4,063
Construction Work in Progress	22,680	24,741
TOTAL	675,599	674,055
Accumulated Depreciation	350,875	351,062
TOTAL - NET	324,724	322,993
OTHER PROPERTY AND INVESTMENTS - Non-Utility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	17,603	24,748
Fuel	23,888	20,139
Materials and Supplies	5,357	5,419
Prepayments	32	-
TOTAL	46,880	50,306
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,674	4,733
Asset Retirement Obligations	975	928
Deferred Property Taxes	2,941	502
Other Deferred Charges	446	464
TOTAL	9,036	6,627
TOTAL ASSETS	$380,759	$380,045

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
CAPITALIZATION		
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	22,006	21,441
Total Common Shareholder's Equity	46,440	45,875
Long-term Debt	44,813	44,811
TOTAL	91,253	90,686
CURRENT LIABILITIES		
Advances from Affiliates	17,745	36,892
Accounts Payable:		
General	719	498
Affiliated Companies	15,447	15,911
Taxes Accrued	10,609	6,070
Interest Accrued	456	911
Obligations Under Capital Leases	78	87
Rent Accrued - Rockport Plant Unit 2	23,427	4,963
Other	37	-
TOTAL	68,518	65,332
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	24,103	24,329
Regulatory Liabilities:		
Asset Removal Costs	27,659	27,822
Deferred Investment Tax Credits	48,755	49,589
SFAS 109 Regulatory Liability, Net	15,074	15,505
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	104,083	105,475
Obligations Under Capital Leases	167	182
Asset Retirement Obligations	1,147	1,125
TOTAL	220,988	224,027
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$380,759	$380,045

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$1,827	$1,796
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	5,734	5,621
Deferred Income Taxes	(656)	(1,230)
Deferred Investment Tax Credits	(834)	(835)
Deferred Property Taxes	(2,439)	(2,329)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(1,392)	(1,392)
Changes in Certain Assets and Liabilities:		
Accounts Receivable	7,145	(3,129)
Fuel, Materials and Supplies	(3,687)	2,309
Accounts Payable	(243)	(3,348)
Taxes Accrued	4,539	4,967
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	83	(1,021)
Change in Other Liabilities	(583)	554
Net Cash Flows From Operating Activities	27,958	20,427
INVESTING ACTIVITIES		
Construction Expenditures	(7,549)	(872)
Net Cash Flows Used For Investing Activities	(7,549)	(872)
FINANCING ACTIVITIES		
Change in Advances from Affiliates	(19,147)	(18,384)
Dividends Paid	(1,262)	(1,171)
Net Cash Flows Used For Financing Activities	(20,409)	(19,555)
Net Decrease in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$-	$-

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $921,000 and $1,123,000 and for income taxes was $(218,000) and $(384,000) in 2004 and 2003, respectively.

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.

Results of Operations

Net Income decreased $35 million for 2004 due mainly to the cessation of the recognition of non-cash earnings related to legislatively mandated capacity auction sales and regulatory assets established in Texas of $36 million, net of tax.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income decreased $37 million primarily due to:

o Decreased Revenues associated with establishing regulatory assets in Texas of $56 million in 2003 (see "Texas Restructuring" in Note 4). These revenues did not continue after 2003.
o Decreased off-system sales, including those to REPs, of $78 million due mainly to lower KWH sales of 31% and a small decrease in the overall average price per KWH.
o Decreased revenues from ERCOT for various services, including balancing energy, which declined $14 million.
o Decreased retail wires revenues of $2 million driven by a 6% decrease in degree-days, offset in part by a 5% increase in the average price per KWH.
o Decreased Reliability Must Run revenues from ERCOT of $5 million which includes both fuel recovery and a fixed cost component decrease of $2 million.
o Decreased fees of $6 million for services we provided to others as their Qualified Scheduling Entity (QSE) due mainly to certain REPs no longer using TCC as their QSE in 2004.
o Increased Other Operation expenses of $8 million due mainly to $5 million of increased ERCOT related transmission expense and higher affiliated ancillary services, as well as an increase of $1 million for emission allowance expense.

The decrease in Operating Income was partially offset by:

o Increases resulting from risk management activities.
o Net decreases in fuel and purchased electricity on a combined basis of $72 million. KWH purchased decreased 87% while the cost per KWH decreased 19%. Although the KWH generated increased 23%, fuel costs decreased 4% attributable mostly to larger amounts of fuel oil burned in 2003.
o Decreased provisions for rate refunds of $14 million due to 2003 Texas fuel issues (see "TCC Fuel Reconciliation" in Note 3).
o Increased transmission revenue of $10 million due to prior year adjustments for affiliated OATT and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
o Decreased Depreciation and Amortization expense of $17 million due mainly to the cessation of depreciation on Texas generation plants classified as "Held For Sale."
o Decreased Income Taxes of $22 million due primarily to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $2 million due mainly to risk management activities.

Interest Charges increased $1 million due primarily to financing activities in 2003 that resulted in an increase in long-term debt outstanding.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the three months ended March 31, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$65,882	$85,420
Cash flow from (used for):		
Operating activities	26,247	50,752
Investing activities	(24,122)	(21,851)
Financing activities	(29,182)	(81,525)
Net decrease in cash and cash equivalents	(27,057)	(52,624)
Cash and cash equivalents at end of period	$38,825	$32,796

Operating Activities

Cash Flow From Operating Activities in 2004 was $26 million primarily due to Net Income, as explained above, and Taxes Accrued, offset in part by Deferred Property Tax, Accounts Payable and Interest Accrued.

Investing Activities

Investing expenditures in 2004 were $24 million due primarily to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Financing Activities

Cash Used For Financing Activities in 2004 reduced Long-term Debt, paid dividends and was partially offset by Advances to Affiliates.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2004 were:

Issuances

None

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$1,055	7.125	2005
Securitization Bonds	28,809	3.540	2005

Significant Factors

We made progress on our planned divestiture of certain Texas generation assets by (1) announcing in January 2004 that we had signed an agreement to sell our 7.8% share of the Oklaunion Power Station for approximately $43 million, subject to closing adjustments, (2) announcing in February 2004 that we had signed an agreement to sell our 25.2% share of the South Texas Project nuclear plant for approximately $333 million, subject to closing adjustments, and (3) announcing in March 2004 that we had signed an agreement to sell our remaining generating assets, including eight natural gas plants, one coal-fired plant and one hydro plant for approximately $430 million, subject to closing adjustments. Subject to certain co-owners' rights of first refusal, we expect all of our announced sales to close before the end of 2004, after receiving appropriate regulatory approvals and clearances. We will file with the Public Utility Commission of Texas to recover net stranded costs associated with each of the sales pursuant to Texas restructuring legislation.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect.

MTM Risk Management Contract Net Liabilities

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 Liabilities Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$11,942
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,889)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	79

```
Change in Fair Value Due to Valuation
 Methodology Changes                                                    -
Changes in Fair Value of Risk Management
 Contracts (d)
(3,226)
Changes in Fair Value of Risk Management Contracts
 Allocated to Regulated Jurisdictions (e)                               -

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Total MTM Risk Management Contract Net Assets                       6,906
Net Cash Flow Hedge Contracts (f)
(24,225)

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Total MTM Risk Management Contract Net Liabilities
 at March 31, 2004
$(17,319)

=========
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(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.
(f)"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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(107)	$174	$(7)	$61	$-	$-	$121
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(809)	832	22	-	-	-	45
Prices Based on Models and Other Valuation Methods (b)	5,802	(93)	62	156	244	569	6,740

Total	$4,886	$913	$77	$217	$244	$569	$6,906

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Three Months Ended March 31, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$(1,828)
Changes in Fair Value (a)	(13,601)
Reclassifications from AOCI to Net Income (b)	(162)
Ending Balance March 31, 2004	$(15,591)

(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 $15,478 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$51	$160	$88	$45	$189	$733	$307	$73

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 $179 million and $206 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$268,858	$382,130
Sales to AEP Affiliates	18,130	46,228
TOTAL	286,988	428,358
OPERATING EXPENSES		
Fuel for Electric Generation	23,106	27,339
Fuel from Affiliates for Electric Generation	40,199	38,289
Purchased Electricity for Resale	10,086	72,122
Purchased Electricity from AEP Affiliates	4,073	11,562
Other Operation	77,807	69,402
Maintenance	15,404	16,099
Depreciation and Amortization	27,058	44,073
Taxes Other Than Income Taxes	22,057	22,979
Income Taxes	12,006	34,483
TOTAL	231,796	336,348
OPERATING INCOME	55,192	92,010
Nonoperating Income	12,102	10,162
Nonoperating Expenses	5,108	5,195
Nonoperating Income Tax Expense (Credit)	(20)	558
Interest Charges	33,129	31,982
Income Before Cumulative Effect of Accounting Change	29,077	64,437
Cumulative Effect of Accounting Change (Net of Tax)	-	122
NET INCOME	29,077	64,559
Preferred Stock Dividend Requirements	60	60
EARNINGS APPLICABLE TO COMMON STOCK	$29,017	$64,499

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$55,292	$132,606	$986,396	$(73,160)	$1,101,134
Common Stock Dividends			(30,201)		(30,201)
Preferred Stock Dividends			(60)		(60)
TOTAL					1,070,873
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,018)	(1,018)
NET INCOME			64,559		64,559
TOTAL COMPREHENSIVE INCOME					63,541
MARCH 31, 2003	$55,292	$132,606	$1,020,694	$(74,178)	$1,134,414
DECEMBER 31, 2003	$55,292	$132,606	$1,083,023	$(61,872)	$1,209,049
Common Stock Dividends			(24,000)		(24,000)
Preferred Stock Dividends			(60)		(60)
TOTAL					1,184,989
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(13,763)	(13,763)
Minimum Pension Liability				(2,466)	(2,466)
NET INCOME			29,077		29,077
TOTAL COMPREHENSIVE INCOME					12,848
MARCH 31, 2004	$55,292	$132,606	$1,088,040	$(78,101)	$1,197,837

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$-	$-
Transmission	773,318	767,970
Distribution	1,382,806	1,376,761
General	223,695	221,354
Construction Work in Progress	57,858	58,953
TOTAL	2,437,677	2,425,038
Accumulated Depreciation and Amortization	702,172	695,359
TOTAL - NET	1,735,505	1,729,679
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,344	1,302
Other Investments	4,639	4,639
TOTAL	5,983	5,941
CURRENT ASSETS		
Cash and Cash Equivalents	38,825	65,882
Advances to Affiliates	35,957	60,699
Accounts Receivable:		
Customers	151,304	146,630
Affiliated Companies	75,481	78,484
Accrued Unbilled Revenues	20,438	23,077
Allowance for Uncollectible Accounts	(1,679)	(1,710)
Materials and Supplies	12,520	11,708
Risk Management Assets	11,038	22,051
Margin Deposits	6,417	3,230
Prepayments and Other Current Assets	7,781	6,770
TOTAL	358,082	416,821
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	2,712	3,249
Wholesale Capacity Auction True-up	480,000	480,000
Unamortized Loss on Reacquired Debt	8,846	9,086
Designated for Securitization	1,257,967	1,253,289
Deferred Debt - Restructuring	11,861	12,015
Other	126,465	133,913
Securitized Transition Assets	679,397	689,399
Long-term Risk Management Assets	3,226	7,627
Deferred Charges	82,653	55,554
TOTAL	2,653,127	2,644,132
Assets Held for Sale - Texas Generation Plants	1,032,807	1,028,134
TOTAL ASSETS	$5,785,504	$5,824,707

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
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	1,088,040	1,083,023
Accumulated Other Comprehensive Income (Loss)	(78,101)	(61,872)
Total Common Shareholder's Equity	1,197,837	1,209,049
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholder's Equity	1,203,777	1,214,989
Long-term Debt	1,773,633	2,053,974
TOTAL	2,977,410	3,268,963
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	488,228	237,651
Accounts Payable:		
General	78,632	90,004
Affiliated Companies	71,322	74,209
Customer Deposits	3,491	1,517
Taxes Accrued	98,670	67,018
Interest Accrued	23,248	43,196
Risk Management Liabilities	29,869	17,888
Obligation Under Capital Leases	420	407
Other	17,927	23,248
TOTAL	811,807	555,138
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,233,564	1,244,912
Long-term Risk Management Liabilities	1,714	2,660
Regulatory Liabilities:		
Asset Removal Costs	96,606	95,415
Deferred Investment Tax Credits	111,177	112,479
Deferred Fuel Costs	69,026	69,026
Retail Clawback	45,527	45,527
Other	50,082	56,984
Obligation Under Capital Leases	592	636
Deferred Credits and Other	155,844	144,833
TOTAL	1,764,132	1,772,472
Liabilities Held for Sale - Texas Generation Plants	232,155	228,134
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,785,504	$5,824,707

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$29,077	$64,559
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	(122)
Depreciation and Amortization	27,058	44,073
Deferred Income Taxes	(3,401)	(2,260)
Deferred Investment Tax Credits	(1,302)	(1,302)
Deferred Property Taxes	(33,660)	(31,590)
Mark-to-Market of Risk Management Contracts	5,035	5,197
Wholesale Capacity Auction True-up	-	(56,000)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	937	(66,835)
Fuel, Materials and Supplies	(500)	14,833
Accounts Payable	(14,259)	39,281
Taxes Accrued	31,652	69,524
Interest Accrued	(19,948)	(26,285)
Change in Other Assets	2,325	10,116
Change in Other Liabilities	3,233	(12,437)
Net Cash Flows From Operating Activities	26,247	50,752
INVESTING ACTIVITIES		
Construction Expenditures	(24,105)	(21,851)
Other	(17)	-
Net Cash Flows Used For Investing Activities	(24,122)	(21,851)
FINANCING ACTIVITIES		
Change in Short-term Debt - Affiliates	-	(650,000)
Issuance of Long-term Debt	-	792,028
Retirement of Long-term Debt	(29,864)	(48,235)
Change in Advances to Affiliates	24,742	(145,057)
Dividends Paid on Common Stock	(24,000)	(30,201)
Dividends Paid on Cumulative Preferred Stock	(60)	(60)
Net Cash Flows Used For Financing Activities	(29,182)	(81,525)
Net Decrease in Cash and Cash Equivalents	(27,057)	(52,624)
Cash and Cash Equivalents at Beginning of Period	65,882	85,420
Cash and Cash Equivalents at End of Period	$38,825	$32,796

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $49,928,000 and $55,483,000 and for income taxes was $(7,567,000) and $(22,959,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

AEP TEXAS NORTH COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income increased $3 million for 2004 due mainly to reduced provisions for refunds of $8 million, net of tax, offset in part by the Cumulative Effect of Accounting Changes of $3 million recorded in 2003.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income increased by $7 million primarily due to:

o Increased Reliability Must Run revenues from ERCOT of $6 million, which include both fuel recovery and a fixed cost component.
o Decreased fuel and purchased electricity on a combined basis of $21 million. KWH generation decreased 3%, while the per-unit cost of fuel increased 10% due primarily to increases in the per-unit cost of natural gas. KWH purchased declined 53%, and the average cost per KWH purchased decreased 23%.
o Decreased provision for rate refunds of $12 million due to fewer Texas fuel issues in 2003 (see "TNC Fuel Reconciliation" in Note 3).
o Increased Transmission revenue of $7 million, due mainly to prior year adjustments for affiliated OATT and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
o Reduced Taxes Other Than Income Taxes of $1 million resulting mainly from lower accrued property taxes.

The increase in Operating Income was partially offset by:

o Decreased off-system sales, including those to retail electric providers, of $27 million due mainly to lower KWH sales of 31% and a small decrease in the overall average price per KWH.
o Revenues from ERCOT decreased $5 million for various services, including balancing energy, due mainly to prior years' adjustments made by ERCOT.
o Reduced wholesale revenues of $1 million due to the loss of several large wholesale customers whose contracts expired and were not renewed.
o Decreases from risk management activities.
o Increased Income Taxes of $2 million due primarily to an increase in pre-tax operating book income.

Other Impacts on Earnings

Interest Charges increased $2 million primarily as a result of refinancing in the first quarter of 2003, reflecting one month of interest charges as compared to three months of related interest for 2004.

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 in 2003.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

Long-term debt issuances and retirements during the first three months of 2004 were:

Issuances

None

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$24,036	6.125	2004

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effects.

MTM Risk Management Contract Net Liabilities

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 Liabilities
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$4,620
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(662)
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	-
Changes in Fair Value of Risk Management Contracts (d)	(1,466)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	

-

Total MTM Risk Management Contract Net Assets
2,524
Net Cash Flow Hedge Contracts (f)
(8,098)

Total MTM Risk Management Contract Net Liabilities at March 31, 2004
$(5,574)

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(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.
(f)"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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actually Quoted - Exchange Traded Contracts	$(62)	$70	$(3)	$24	$-	$-	$29
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(177)	334	8	-	-	-	165
Prices Based on Models and Other Valuation Methods (b)	1,953	(37)	24	63	98	229	2,330
Total	$1,714	$367	$29	$87	$98	$229	$2,524

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Three Months Ended March 31, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$(601)
Changes in Fair Value (a)	(4,555)
Reclassifications from AOCI to Net Income (b)	(55)
Ending Balance March 31, 2004	$(5,211)

(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 $5,166 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low

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---   ----   -------  ---         ---   ----   -------
---
$20    $64     $35    $18         $76   $294    $123
$29
```

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 $28 million and $33 million at March 31, 2004 and December 31, 2003, 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.

AEP TEXAS NORTH COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$88,712	$96,061
Sales to AEP Affiliates	14,718	20,201
TOTAL	103,430	116,262
OPERATING EXPENSES		
Fuel for Electric Generation	7,500	11,461
Fuel from Affiliates for Electric Generation	11,224	6,085
Purchased Electricity for Resale	18,023	24,778
Purchased Electricity from AEP Affiliates	3,532	19,345
Other Operation	20,524	20,619
Maintenance	4,683	4,141
Depreciation and Amortization	9,692	9,532
Taxes Other Than Income Taxes	5,104	6,033
Income Taxes	5,941	4,403
TOTAL	86,223	106,397
OPERATING INCOME	17,207	9,865
Nonoperating Income	13,756	13,471
Nonoperating Expenses	10,936	11,567
Nonoperating Income Tax Expense	894	339
Interest Charges	6,180	4,665
Income Before Cumulative Effect of Accounting Changes	12,953	6,765
Cumulative Effect of Accounting Changes (Net of Tax)	-	3,071
NET INCOME	12,953	9,836
Preferred Stock Dividend Requirements	26	26
EARNINGS APPLICABLE TO COMMON STOCK	$12,927	$9,810

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$137,214	$2,351	$71,942	$(30,763)	$180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(26)		(26)
TOTAL					175,748
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(421)	(421)
Minimum Pension Liability				(7)	(7)
NET INCOME			9,836		9,836
TOTAL COMPREHENSIVE INCOME					9,408
MARCH 31, 2003	$137,214	$2,351	$76,782	$(31,191)	$185,156
DECEMBER 31, 2003	$137,214	$2,351	$125,428	$(26,718)	$238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(26)		(26)
TOTAL					236,249
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(4,610)	(4,610)
NET INCOME			12,953		12,953
TOTAL COMPREHENSIVE INCOME					8,343
MARCH 31, 2004	$137,214	$2,351	$136,355	$(31,328)	$244,592

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$360,422	$360,463
Transmission	271,304	268,695
Distribution	460,123	456,278
General	119,342	117,792
Construction Work in Progress	28,834	30,199
TOTAL	1,240,025	1,233,427
Accumulated Depreciation and Amortization	466,792	460,513
TOTAL - NET	773,233	772,914
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,282	1,286
TOTAL	1,282	1,286
CURRENT ASSETS		
Cash and Cash Equivalents	2,835	2,863
Advances to Affiliates	19,990	41,593
Accounts Receivable:		
Customers	62,711	56,670
Affiliated Companies	19,980	28,910
Accrued Unbilled Revenues	4,119	4,871
Miscellaneous	416	3,411
Allowance for Uncollectible Accounts	(293)	(175)
Fuel Inventory	8,582	10,925
Materials and Supplies	8,773	8,866
Risk Management Assets	4,739	10,340
Margin Deposits	2,328	1,285
Prepayments and Other	1,883	1,834
TOTAL	136,063	171,393
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Fuel Costs	26,680	26,680
Deferred Debt - Restructuring	6,458	6,579
Unamortized Loss on Reacquired Debt	3,444	3,929
Other	3,140	3,332
Long-term Risk Management Assets	1,296	3,106
Deferred Charges	35,339	20,290
TOTAL	76,357	63,916
TOTAL ASSETS	$986,935	$1,009,509

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
CAPITALIZATION		
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	136,355	125,428
Accumulated Other Comprehensive Income (Loss)	(31,328)	(26,718)
Total Common Shareholder's Equity	244,592	238,275
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholder's Equity	246,949	240,632
Long-term Debt	314,279	314,249
TOTAL	561,228	554,881
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	18,469	42,505
Accounts Payable:		
General	19,923	28,190
Affiliated Companies	37,641	40,601
Customer Deposits	466	161
Taxes Accrued	31,412	22,877
Interest Accrued	4,076	6,038
Risk Management Liabilities	10,920	8,658
Obligations Under Capital Leases	202	203
Other	7,112	9,419
TOTAL	130,221	158,652
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	110,842	113,019
Long-term Risk Management Liabilities	689	1,094
Regulatory Liabilities:		
Asset Removal Costs	78,078	76,740
Deferred Investment Tax Credits	19,651	19,990
Retail Clawback	11,804	11,804
Excess Earnings	14,141	14,262
SFAS 109 Regulatory Liability, Net	13,349	13,655
Other	1,724	1,826
Obligations Under Capital Leases	247	270
Deferred Credits and Other	44,961	43,316
TOTAL	295,486	295,976
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$986,935	$1,009,509

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$12,953	$9,836
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(3,071)
Depreciation and Amortization	9,692	9,532
Deferred Income Taxes	(1)	(5,666)
Deferred Investment Tax Credits	(339)	(380)
Deferred Property Taxes	(11,100)	(10,868)
Mark-to-Market of Risk Management Contracts	2,096	608
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	6,754	36,645
Fuel, Materials and Supplies	2,436	3,306
Accounts Payable	(11,227)	(54,482)
Taxes Accrued	8,535	21,728
Change in Other Assets	(6,128)	(2,767)
Change in Other Liabilities	(1,118)	5,646
Net Cash Flows From Operating Activities	12,553	10,067
INVESTING ACTIVITIES		
Construction Expenditures	(8,122)	(10,197)
Net Cash Flows Used For Investing Activities	(8,122)	(10,197)
FINANCING ACTIVITIES		
Change in Short-term Debt - Affiliates	-	(125,000)
Issuance of Long-term Debt	-	222,455
Retirement of Long-term Debt	(24,036)	-
Change in Advances to Affiliates	21,603	(88,867)
Dividends Paid on Common Stock	(2,000)	(4,970)
Dividends Paid on Cumulative Preferred Stock	(26)	(26)
Net Cash Flows From (Used For) Financing Activities	(4,459)	3,592
Net Increase (Decrease) in Cash and Cash Equivalents	(28)	3,462
Cash and Cash Equivalents at Beginning of Period	2,863	1,219
Cash and Cash Equivalents at End of Period	$2,835	$4,681

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $7,568,000 and $2,021,000 and for income taxes was ($412,000) and ($8,873,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

Results of Operations

Net Income for the first quarter of 2004 decreased $92 million from the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003 and an increase in Depreciation and Amortization expense of $12 million over the first quarter of 2003.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income for 2004 decreased by $26 million from 2003 primarily due to the following:

o An $11 million decrease in revenues from risk management activities included in Operating Income.
o A decrease of $3 million in Sales to AEP Affiliates due to decreased power available for sale caused by planned plant outages in the first quarter of 2004.
o An increase in Depreciation and Amortization expense of $12 million primarily due to reduced expense in 2003 attributable to the adoption of SFAS 143 for regulated operations and to a lesser degree, due to a greater depreciable base in 2004 which included the addition of capitalized software costs.
o An increase in Maintenance expense of $9 million primarily due to planned maintenance at Amos and Kanawha River Plants relating to scheduled outages in 2004.
o An increase in Other Operation expense of $7 million primarily due to higher employee-related expenses in the first quarter of 2004.
o A $9 million increase in purchased power essentially offset by decreased fuel expenses as purchased power was used to offset decreased generation resulting from the planned plant outages in 2004.

The decrease in Operating Income for 2004 was partially offset by:

o An increase in off-system sales and transmission revenues totaling $4 million.
o A decrease in Income Taxes of $9 million due to the decrease in pre-tax book operating income in 2004.

Other Impacts on Earnings

Nonoperating income increased $10 million in the first quarter of 2004 compared to 2003 primarily due to reduced losses from risk management activities resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area. The increase in nonoperating income was partially offset by a $3 million increase in nonoperating income taxes resulting from an increase in pre-tax nonoperating book income. Interest charges decreased $4 million in the first quarter of 2004 from the prior year period due to lower debt levels and reduced interest rates and increased Allowance for Funds Used During Construction in 2004.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million is due to the implementation of SFAS 143 and EITF 02-3 in 2003.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for the three months ended March 31, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$45,881	$4,285
Cash flow from (used for):		
Operating activities	182,058	220,018
Investing activities	(91,039)	(54,363)
Financing activities	(131,630)	(159,491)
Net increase (decrease) in cash and cash equivalents	(40,611)	6,164
Cash and cash equivalents at end of period	$5,270	$10,449

Operating Activities

Cash Flows From Operating Activities in the first quarter of 2004 were $182 million primarily due to Net Income and changes in Accounts Receivable and accrued expenses.

Investing Activities

Construction expenditures in 2004 versus 2003 increased $34 million. The current year expenditures of $91 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Financing Activities

In 2004, we retired $40 million of Installment Purchase Contracts, paid $25 million in dividends and repaid $66 million of Advances from Affiliates.

Financing Activity

Long-term debt issuances and retirements during the first quarter of 2004 were:

Issuances

None.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	

Installment Purchase Contracts	$40,000	5.45
2019		

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$68,066
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(11,026)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	1,050
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	9,916
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	4,899
Total MTM Risk Management Contract Net Assets	72,905
Net Cash Flow Hedge Contracts (f)	(4,272)
DETM Assignment (g)	(29,111)
Total MTM Risk Management Contract Net Assets at March 31, 2004	$39,522

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "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.
(e) "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.
(f) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss). (g) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(5,053)	$2,303	$(92)	$804	$-	$-	$(2,038)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	23,710	14,113	6,191	2,187	1,145	-	47,346
Prices Based on Models and Other Valuation Methods (b)	(123)	260	4,234	5,696	5,596	11,934	27,597
Total	$18,534	$16,676	$10,333	$8,687	$6,741	$11,934	$72,905

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2004

	Power	Foreign Currency	Interest Rate	Consolidated
		(in thousands)		
Beginning Balance December 31, 2003	$359	$(183)	$(1,745)	$(1,569)
Changes in Fair Value (a)	(2,887)	-	-	(2,887)
Reclassifications from AOCI to Net Income (b)	(249)	2	84	(163)
Ending Balance March 31, 2004	$(2,777)	$(181)	$(1,661)	$(4,619)

(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 $1,630 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$672	$2,123	$1,162	$590	$596	$2,314	$969	$230

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 $86 million and $102 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$472,575	$479,333
Sales to AEP Affiliates	53,882	56,895
TOTAL	526,457	536,228
OPERATING EXPENSES		
Fuel for Electric Generation	110,711	119,865
Purchased Electricity for Resale	16,644	17,118
Purchased Electricity from AEP Affiliates	90,487	80,720
Other Operation	68,907	62,115
Maintenance	41,320	32,738
Depreciation and Amortization	47,913	36,008
Taxes Other Than Income Taxes	23,453	25,079
Income Taxes	40,440	49,901
TOTAL	439,875	423,544
OPERATING INCOME	86,582	112,684
Nonoperating Income (Loss)	5,547	(4,300)
Nonoperating Expenses	2,533	3,858
Nonoperating Income Tax Credit	(362)	(3,733)
Interest Charges	25,437	29,106
Income Before Cumulative Effect of Accounting Changes	64,521	79,153
Cumulative Effect of Accounting Changes (Net of Tax)	-	77,257
NET INCOME	64,521	156,410
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	823	984
EARNINGS APPLICABLE TO COMMON STOCK	$63,698	$155,426

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$260,458	$717,242	$260,439	$(72,082)	$1,166,057
Common Stock Dividends			(32,066)		(32,066)
Preferred Stock Dividends			(361)		(361)
Capital Stock Expense		623	(623)		-
SFAS 71 Reapplication		162			162
TOTAL					1,133,792
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(12,518)	(12,518)
NET INCOME			156,410		156,410
TOTAL COMPREHENSIVE INCOME					143,892
MARCH 31, 2003	$260,458	$718,027	$383,799	$(84,600)	$1,277,684
DECEMBER 31, 2003	$260,458	$719,899	$408,718	$(52,088)	$1,336,987
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		623	(623)		-
TOTAL					1,311,787
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(3,050)	(3,050)
NET INCOME			64,521		64,521
TOTAL COMPREHENSIVE INCOME					61,471
MARCH 31, 2004	$260,458	$720,522	$447,416	$(55,138)	$1,373,258

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,298,815	$2,287,043
Transmission	1,245,757	1,240,889
Distribution	2,018,675	2,006,329
General	301,462	294,786
Construction Work in Progress	353,053	311,884
TOTAL	6,217,762	6,140,931
Accumulated Depreciation and Amortization	2,350,438	2,321,360
TOTAL - NET	3,867,324	3,819,571
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	20,503	20,574
Other Investments	24,586	26,668
TOTAL	45,089	47,242
CURRENT ASSETS		
Cash and Cash Equivalents	5,270	45,881
Accounts Receivable:		
Customers	116,260	133,717
Affiliated Companies	114,535	137,281
Accrued Unbilled Revenues	22,467	35,020
Miscellaneous	4,668	3,961
Allowance for Uncollectible Accounts	(5,227)	(2,085)
Fuel Inventory	50,775	42,806
Materials and Supplies	89,137	71,978
Risk Management Assets	95,607	71,189
Margin Deposits	6,865	11,525
Prepayments and Other	13,543	13,301
TOTAL	513,900	564,574
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Transition Regulatory Assets	28,651	30,855
SFAS 109 Regulatory Asset, Net	326,533	325,889
Unamortized Loss on Reacquired Debt	18,852	19,005
Other Regulatory Assets	44,186	41,447
Long-term Risk Management Assets	94,899	70,900
Deferred Property Taxes	38,440	35,343
Other Deferred Charges	22,080	22,185
TOTAL	573,641	545,624
TOTAL ASSETS	$4,999,954	$4,977,011

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
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	720,522	719,899
Retained Earnings	447,416	408,718
Accumulated Other Comprehensive Income (Loss)	(55,138)	(52,088)
Total Common Shareholder's Equity	1,373,258	1,336,987
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholder's Equity	1,391,042	1,354,771
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,360	5,360
Long-term Debt	1,658,715	1,703,073
TOTAL	3,055,117	3,063,204
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	166,009	161,008
Advances from Affiliates	16,566	82,994
Accounts Payable:		
General	133,897	140,497
Affiliated Companies	62,635	81,812
Customer Deposits	44,914	33,930
Taxes Accrued	77,169	50,259
Interest Accrued	39,982	22,113
Risk Management Liabilities	81,440	51,430
Obligations Under Capital Leases	8,384	9,218
Other	54,309	60,289
TOTAL	685,305	693,550
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	817,099	803,355
Regulatory Liabilities:		
Asset Removal Costs	94,638	92,497
Deferred Investment Tax Credits	29,456	30,545
Over Recovery of Fuel Cost	71,203	68,704
Other Regulatory Liabilities	24,762	17,326
Long-term Risk Management Liabilities	69,544	54,327
Obligations Under Capital Leases	14,999	16,134
Asset Retirement Obligation	22,201	21,776
Deferred Credits and Other	115,630	115,593
TOTAL	1,259,532	1,220,257
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,999,954	$4,977,011

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$64,521	$156,410
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(77,257)
Depreciation and Amortization	47,913	36,008
Deferred Income Taxes	14,742	1,005
Deferred Investment Tax Credits	(1,089)	245
Deferred Power Supply Costs, Net	2,499	63,837
Mark to Market of Risk Management Contracts	(8,015)	5,383
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	55,191	13,830
Fuel, Materials and Supplies	(25,128)	12,018
Accounts Payable	(25,777)	(14,074)
Taxes Accrued	26,910	59,261
Interest Accrued	17,869	16,785
Incentive Plan Accrued	(3,172)	(9,595)
Rate Stabilization Deferral	-	(75,601)
Change in Operating Reserves	(69)	20,095
Change in Other Assets	(2,073)	(14,446)
Change in Other Liabilities	17,736	26,114
Net Cash Flows From Operating Activities	182,058	220,018
INVESTING ACTIVITIES		
Construction Expenditures	(91,067)	(56,627)
Proceeds from Sale of Property and Other	28	2,264
Net Cash Flows Used For Investing Activities	(91,039)	(54,363)
FINANCING ACTIVITIES		
Retirement of Long-term Debt	(40,002)	-
Change in Advances from Affiliates, Net	(66,428)	(127,064)
Dividends Paid on Common Stock	(25,000)	(32,066)
Dividends Paid on Cumulative Preferred Stock	(200)	(361)
Net Cash Flows Used For Financing Activities	(131,630)	(159,491)
Net Increase (Decrease) in Cash and Cash Equivalents	(40,611)	6,164
Cash and Cash Equivalents at Beginning of Period	45,881	4,285
Cash and Cash Equivalents at End of Period	$5,270	$10,449

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $5,214,000 and $11,191,000 and for income taxes was $1,599,000 and $(11,498,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter 2004 Compared to First Quarter 2003

The decrease in Net Income of $21 million in 2004 compared to 2003 was primarily due to a $27 million net-of-tax Cumulative Effect of Accounting Changes in the first quarter of 2003, a $3 million increase in Depreciation and Amortization expense and a $6 million increase in Nonoperating Income Taxes, which was offset by a $3 million increase in total operating revenues and a $12 million increase in nonoperating income associated with risk management activities.

Operating Income

Operating Income decreased $1 million primarily due to:

o A decrease of $3 million in wholesale sales to municipal customers as the result of the expiration of the final municipal contract at the end of 2003.
o A decrease of $1 million in sales for resale to affiliated companies due to lower price realizations during 2004.
o A decrease of $2 million in operating revenues relating to risk management activities as a result of lower volumes.
o An increase of $2 million in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages.
o An increase of $3 million in Depreciation and Amortization expense as a result of a greater depreciable base in 2004, including capital software costs and the increased amortization of regulatory assets due to a federal tax adjustment, which increased the regulatory asset amount, and a corresponding quarterly adjustment to the amortization amount.

The decrease in Operating Income was partially offset by:

o An increase of $9 million in retail electric revenues primarily due to growth in the residential and commercial customer base and increased KWH usage per customer in the first quarter of 2004.
o A decrease of $1 million in Income Taxes due to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Nonoperating Income increased $12 million primarily due to favorable results from risk management activities in the first quarter of 2004 compared to losses that were recorded in the first quarter of 2003.

Nonoperating Income Tax increased $6 million due to an increase in pre-tax nonoperating book income.

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.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	A3	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements in the first three months of 2004.

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$38,337
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(6,212)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	646
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	12,040
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	44,811
Net Cash Flow Hedge Contracts (f)	(2,626)
DETM Assignment (g)	(17,893)
Total MTM Risk Management Contract Net Assets at March 31, 2004	$24,292

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.
(f)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See Note 17 "Related Party Transactions" in the 2003 Annual Report.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(3,106)	$1,416	$(57)	$494	$-	$-	$(1,253)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	14,573	8,675	3,805	1,343	704	-	29,100
Prices Based on Models and Other Valuation Methods (b)	(75)	160	2,603	3,501	3,440	7,335	16,964
Total	$11,392	$10,251	$6,351	$5,338	$4,144	$7,335	$44,811

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Three Months Ended March 31, 2004

	Power
(in thousands)	
Beginning Balance December 31, 2003	$202
Changes in Fair Value (a)	(1,745)
Reclassifications from AOCI to Net Income (b)	(165)

Ending Balance March 31, 2004	$(1,708)

(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 $790 thousand loss.

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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$413	$1,305	$714	$363	$336	$1,303	$546	$130

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 $86 million and $98 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$343,686	$338,437
Sales to AEP Affiliates	18,619	20,768
TOTAL	362,305	359,205
OPERATING EXPENSES		
Fuel for Electric Generation	41,851	47,540
Fuel From Affiliates for Electric Generation	8,848	4,503
Purchased Electricity for Resale	4,681	4,198
Purchased Electricity from AEP Affiliates	81,715	82,149
Other Operation	57,681	56,385
Maintenance	16,826	14,559
Depreciation and Amortization	36,818	33,737
Taxes Other Than Income Taxes	35,326	35,608
Income Taxes	24,465	25,375
TOTAL	308,211	304,054
OPERATING INCOME	54,094	55,151
Nonoperating Income (Loss)	5,078	(6,676)
Nonoperating Expenses	734	2,201
Nonoperating Income Tax Expense (Credit)	919	(5,547)
Interest Charges	12,814	13,462
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	44,705	38,359
Cumulative Effect of Accounting Changes (Net of Tax)	-	27,283
NET INCOME	44,705	65,642
Preferred Stock - Capital Stock Expense	254	254
EARNINGS APPLICABLE TO COMMON STOCK	$44,451	$65,388

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$41,026	$575,384	$290,611	$(59,357)	$847,664
Common Stock Dividends Declared			(38,311)		(38,311)
Capital Stock Expense		254	(254)		-
TOTAL					809,353
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(7,343)	(7,343)
NET INCOME			65,642		65,642
TOTAL COMPREHENSIVE INCOME					58,299
MARCH 31, 2003	$41,026	$575,638	$317,688	$(66,700)	$867,652
DECEMBER 31, 2003	$41,026	$576,400	$326,782	$(46,327)	$897,881
Common Stock Dividends Declared			(31,250)		(31,250)
Capital Stock Expense		254	(254)		-
TOTAL					866,631
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,910)	(1,910)
NET INCOME			44,705		44,705
TOTAL COMPREHENSIVE INCOME					42,795
MARCH 31, 2004	$41,026	$576,654	$339,983	$(48,237)	$909,426

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,614,315	$1,610,888
Transmission	427,609	425,512
Distribution	1,265,858	1,253,760
General	168,434	166,002
Construction Work in Progress	115,099	114,281
TOTAL	3,591,315	3,570,443
Accumulated Depreciation and Amortization	1,410,524	1,389,586
TOTAL - NET	2,180,791	2,180,857
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	22,006	22,417
Other Investments	7,838	8,663
TOTAL	29,844	31,080
CURRENT ASSETS		
Cash and Cash Equivalents	4,144	4,142
Advances to Affiliates, Net	18,058	-
Accounts Receivable:		
Customers	36,934	47,099
Affiliated Companies	53,689	68,168
Accrued Unbilled Revenues	24,487	23,723
Miscellaneous	5,665	5,257
Allowance for Uncollectible Accounts	(150)	(531)
Fuel	18,139	14,365
Materials and Supplies	56,112	44,377
Risk Management Assets	58,764	40,095
Margin Deposits	3,956	6,636
Prepayments and Other	12,691	12,444
TOTAL	292,489	265,775
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Assets, Net	16,215	16,027
Transition Regulatory Assets	180,281	188,532
Unamortized Loss on Reacquired Debt	13,418	13,659
Other	21,692	24,966
Long-term Risk Management Assets	58,329	39,932
Deferred Property Taxes	47,251	62,262
Deferred Charges	19,339	15,276
TOTAL	356,525	360,654
TOTAL ASSETS	$2,859,649	$2,838,366

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
CAPITALIZATION		
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	576,654	576,400
Retained Earnings	339,983	326,782
Accumulated Other Comprehensive Income (Loss)	(48,237)	(46,327)
Total Common Shareholder's Equity	909,426	897,881
Long-term Debt	842,948	886,564
TOTAL	1,752,374	1,784,445
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	54,695	11,000
Advances from Affiliates, Net	-	6,517
Accounts Payable:		
General	51,621	58,220
Affiliated Companies	49,503	53,572
Customer Deposits	25,775	19,727
Taxes Accrued	125,135	132,853
Interest Accrued	9,945	16,528
Risk Management Liabilities	50,056	28,966
Obligations Under Capital Leases	4,057	4,221
Other	24,472	25,364
TOTAL	395,259	356,968
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	465,384	458,498
Regulatory Liabilities:		
Asset Removal Costs	100,382	99,119
Deferred Investment Tax Credits	30,045	30,797
Long-term Risk Management Liabilities	42,745	30,598
Obligations Under Capital Leases	10,497	11,397
Asset Retirement Obligations	8,911	8,740
Deferred Credits and Other	54,052	57,804
TOTAL	712,016	696,953
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,859,649	$2,838,366

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$44,705	$65,642
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(27,283)
Depreciation and Amortization	36,818	33,737
Deferred Income Taxes	7,726	(3,095)
Deferred Investment Tax Credits	(752)	(763)
Mark-to-Market of Risk Management Contracts	(6,766)	10,958
Gain on Sale of Assets	(1,786)	-
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	23,091	16,673
Fuel, Materials and Supplies	(15,509)	8,498
Accounts Payable	(10,668)	(39,247)
Taxes Accrued	(7,718)	11,817
Interest Accrued	(6,583)	3,894
Change in Other Assets	16,473	(2,240)
Change in Other Liabilities	2,041	9,141
Net Cash Flows From Operating Activities	81,072	87,732
INVESTING ACTIVITIES		
Construction Expenditures	(27,360)	(27,269)
Proceeds from Sale of Property and Other	2,115	190
Net Cash Flows Used For Investing Activities	(25,245)	(27,079)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	494,350
Change in Advances to/from Affiliates, Net	(24,575)	(56,203)
Retirement of Long-term Debt - Nonaffiliated	-	(44,000)
Retirement of Long-term Debt - Affiliated	-	(160,000)
Change in Short-term Debt - Affiliates	-	(250,000)
Dividends Paid on Common Stock	(31,250)	(38,311)
Net Cash Flows Used For Financing Activities	(55,825)	(54,164)
Net Increase in Cash and Cash Equivalents	2	6,489
Cash and Cash Equivalents at Beginning of Period	4,142	1,479
Cash and Cash Equivalents at End of Period	$4,144	$7,968

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $18,971,000 and $9,219,000 and for income taxes was $(3,806,000) and $(16,019,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

During 2004, Net Income increased $15 million including an unfavorable $3 million Cumulative Effect of Accounting Change in 2003. During 2004, Net Income Before Cumulative Effect of Accounting Change increased $12 million due to reduced financing costs and an improvement in margins on nonoperating risk management activities.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income decreased $3 million primarily due to:

o Decreased Sales to AEP Affiliates of $11 million due to declines in the price and volume of sales to the AEP Power Pool reflecting lower demand for electricity and lower capacity revenues.
o Increased Maintenance expense of $7 million due primarily to the cost of a planned maintenance outage at one unit of Rockport Plant and increased cost of overhead lines and their right-of-way maintenance.
o Increased Income Tax expense of $3 million reflecting an increase in pre-tax operating income.

The decrease in Operating Income was partially offset by:

o Increased retail revenues of $7 million due primarily to an improvement in industrial sales reflecting the recovery of the economy and the end of amortization for Cook outage settlements.
o Decreased Fuel for Electric Generation expense of $9 million reflecting a change in fuel mix as nuclear generation increased 21% and coal-fired generation declined 22% due to generating unit availability.
o Decreased Taxes Other Than Income Taxes of $2 million primarily due to decreased Federal Insurance Contributions Act taxes reflecting a reduction in employees from the sustained earnings improvement initiative and timing of payroll accrual.

Other Impacts on Earnings

Nonoperating Income increased $14 million primarily due to improved risk management activities.

Nonoperating Income Taxes increased $6 million reflecting the increase in pre-tax nonoperating income.

Interest Charges decreased $6 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, maturity of $30 million first mortgage bonds in November 2003 and the refinancing of $65 million installment purchase contracts at lower interest rates.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to the implementation of the requirements of EITF 02-3 related to mark-to-market accounting for risk management contracts that are not derivatives.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	BBB+
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for the first three months of 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$3,914	$3,237
Cash flow from (used for):		
Operating activities	182,883	80,169
Investing activities	(36,340)	(28,222)
Financing activities	(147,177)	(48,664)
Net increase (decrease) in cash and cash equivalents	(634)	3,283
Cash and cash equivalents at end of period	$3,280	$6,520

Operating Activities

Operating activities during 2004 provided $103 million more cash than during 2003 largely due to increased net income of $15 million and improved working capital requirements.

Investing Activities

Cash flows Used For Investing Activities during 2004 were $8 million higher than 2003 primarily due to increased construction expenditures. Construction expenditures for transmission and distribution assets were incurred to upgrade or replace equipment and improve reliability.

Financing Activities

Financing activities for 2004 used $99 million more cash from operations than during 2003 primarily to reduce short-term debt outstanding and pay common dividends.

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2004.

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. Our off-balance sheet arrangement has not changed significantly from year-end 2003 and is comprised of a sale and leaseback transaction entered into by AEGCo and I&M with an unrelated unconsolidated trustee.

Our current plans limit the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that are entered into in the normal course of business. For complete information on this off-balance sheet arrangement see "Off-balance Sheet Arrangements" in "Management's Financial Discussion and Analysis" section of our 2003 Annual Report.

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$41,995
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(6,529)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	708
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	4,832
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	8,064
Total MTM Risk Management Contract Net Assets	49,070
Net Cash Flow Hedge Contracts (f)	(2,878)
DETM Assignment (g)	(19,612)
Total MTM Risk Management Contract Net Assets at March 31, 2004	$26,580

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.

(f)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g)See Note 17 "Related Party Transactions" in the 2003 Annual Report.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(3,404)	$1,552	$(62)	$542	$-	$-	$(1,372)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	15,992	9,508	4,170	1,473	771	-	31,914
Prices Based on Models and Other Valuation Methods (b)	(147)	175	2,853	3,837	3,770	8,040	18,528
Total	$12,441	$11,235	$6,961	$5,852	$4,541	$8,040	$49,070

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2004

	Power
(in thousands)	
Beginning Balance December 31, 2003	$222
Changes in Fair Value (a)	(1,912)
Reclassifications from AOCI to Net Income (b)	(181)
Ending Balance March 31, 2004	$(1,871)

(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 $865 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$453	$1,430	$783	$398	$368	$1,429	$598	$142

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 $61 million and $79 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$353,398	$349,787
Sales to AEP Affiliates	57,645	68,811
TOTAL	411,043	418,598
OPERATING EXPENSES		
Fuel for Electric Generation	64,041	73,094
Purchased Electricity for Resale	6,363	6,282
Purchased Electricity from AEP Affiliates	63,128	65,898
Other Operation	101,058	101,381
Maintenance	38,042	31,367
Depreciation and Amortization	42,715	43,726
Taxes Other Than Income Taxes	15,216	16,821
Income Taxes	24,299	21,039
TOTAL	354,862	359,608
OPERATING INCOME	56,181	58,990
Nonoperating Income	20,588	6,274
Nonoperating Expenses	14,851	15,590
Nonoperating Income Tax Expense (Credit)	1,613	(4,451)
Interest Charges	17,929	23,438
Net Income Before Cumulative Effect of Accounting Change	42,376	30,687
Cumulative Effect of Accounting Change (Net of Tax)	-	(3,160)
NET INCOME	42,376	27,527
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	118	1,149
EARNINGS APPLICABLE TO COMMON STOCK	$42,258	$26,378

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$56,584	$858,560	$143,996	$(40,487)	$1,018,653
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(1,115)		(1,115)
Capital Stock Expense		34	(34)		-
					1,007,538
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(7,857)	(7,857)
NET INCOME			27,527		27,527
TOTAL COMPREHENSIVE INCOME					19,670
MARCH 31, 2003	$56,584	$858,594	$160,374	$(48,344)	$1,027,208
DECEMBER 31, 2003	$56,584	$858,694	$187,875	$(25,106)	$1,078,047
Common Stock Dividends			(29,646)		(29,646)
Preferred Stock Dividends			(84)		(84)
Capital Stock Expense		34	(34)		-
					1,048,317
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,093)	(2,093)
NET INCOME			42,376		42,376
TOTAL COMPREHENSIVE INCOME					40,283
MARCH 31, 2004	$56,584	$858,728	$200,487	$(27,199)	$1,088,600

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,889,689	$2,878,051
Transmission	1,002,532	1,000,926
Distribution	964,987	958,966
General (including nuclear fuel)	270,024	274,283
Construction Work in Progress	191,518	193,956
TOTAL	5,318,750	5,306,182
Accumulated Depreciation and Amortization	2,516,959	2,490,912
TOTAL - NET	2,801,791	2,815,270
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,035,851	982,394
Non-Utility Property, Net	50,858	52,303
Other Investments	41,823	43,797
TOTAL	1,128,532	1,078,494
CURRENT ASSETS		
Cash and Cash Equivalents	3,280	3,914
Advances to Affiliates	16,625	-
Accounts Receivable:		
Customers	49,917	63,084
Affiliated Companies	84,378	124,826
Miscellaneous	5,020	4,498
Allowance for Uncollectible Accounts	(63)	(531)
Fuel	34,145	33,968
Materials and Supplies	119,117	105,328
Risk Management Assets	64,429	44,071
Margin Deposits	4,323	7,245
Prepayments and Other	11,885	10,673
TOTAL	393,056	397,076
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	148,374	151,973
Incremental Nuclear Refueling Outage Expenses, Net	44,147	57,326
Other	73,873	66,978
Long-term Risk Management Assets	63,933	43,768
Deferred Property Taxes	29,875	21,916
Deferred Charges and Other Assets	25,976	26,270
TOTAL	386,178	368,231
TOTAL ASSETS	$4,709,557	$4,659,071

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
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	858,728	858,694
Retained Earnings	200,487	187,875
Accumulated Other Comprehensive Income (Loss)	(27,199)	(25,106)
Total Common Shareholder's Equity	1,088,600	1,078,047
Cumulative Preferred Stock - Not Subject to Mandatory Redemption	8,101	8,101
Total Shareholder's Equity	1,096,701	1,086,148
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	61,445	63,445
Long-term Debt	1,135,101	1,134,359
TOTAL	2,293,247	2,283,952
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	205,000	205,000
Advances from Affiliates	-	98,822
Accounts Payable:		
General	77,610	101,776
Affiliated Companies	42,432	47,484
Customer Deposits	30,827	21,955
Taxes Accrued	79,943	42,189
Interest Accrued	22,970	17,963
Risk Management Liabilities	54,931	31,898
Obligations Under Capital Leases	6,212	6,528
Other	76,141	57,675
TOTAL	596,066	631,290
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	334,149	337,376
Regulatory Liabilities:		
Asset Removal Costs	266,306	263,015
Deferred Investment Tax Credits	88,446	90,278
Excess ARO for Nuclear Decommissioning	251,539	215,715
Other	82,673	61,268
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	69,252	70,179
Long-term Risk Management Liabilities	46,851	33,537
Obligations Under Capital Leases	30,219	31,315
Asset Retirement Obligations	562,918	553,219
Deferred Credits and Other	87,891	87,927
TOTAL	1,820,244	1,743,829
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,709,557	$4,659,071

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$42,376	$27,527
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	3,160
Depreciation and Amortization	42,715	43,726
Deferred Income Taxes	1,895	(12,367)
Deferred Investment Tax Credits	(1,832)	(1,835)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,179	9,410
Unrecovered Fuel and Purchased Power Costs	(120)	9,375
Amortization of Nuclear Outage Costs	-	10,000
Mark-to-Market of Risk Management Contracts	(7,396)	10,543
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	52,625	(6,726)
Fuel, Materials and Supplies	(13,966)	822
Accounts Payable	(29,218)	(49,480)
Taxes Accrued	37,754	19,166
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Change in Other Assets	(6,446)	3,649
Change in Other Liabilities	32,853	(5,265)
Net Cash Flows From Operating Activities	182,883	80,169
INVESTING ACTIVITIES		
Construction Expenditures	(36,353)	(28,234)
Other	13	12
Net Cash Flows Used For Investing Activities	(36,340)	(28,222)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(2,000)	-
Change in Advances to/from Affiliates, Net	(115,447)	(37,549)
Dividends Paid on Common Stock	(29,646)	(10,000)
Dividends Paid on Cumulative Preferred Stock	(84)	(1,115)
Net Cash Flows Used For Financing Activities	(147,177)	(48,664)
Net Increase (Decrease) in Cash and Cash Equivalents	(634)	3,283
Cash and Cash Equivalents at Beginning of Period	3,914	3,237
Cash and Cash Equivalents at End of Period	$3,280	$6,520

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $12,007,000 and $18,211,000 and for income taxes was ($5,480,000) and $20,011,000 in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter 2004 Compared to First Quarter 2003

Net Income for the first quarter of 2004 increased $2 million over the first quarter of 2003 primarily due to reduced losses on risk management activities, partially offset by the Cumulative Effect of Accounting Change recorded in 2003.

Operating Income

Operating Income for 2004 decreased $1 million primarily due to:

o A decrease in Sales to AEP Affiliates of $2 million due to a decline in available power caused by a planned plant outage at Rockport Unit 2 in early February through March of 2004. Our share of Rockport's generation was down 30% in the first quarter of 2004 compared to 2003.
o Fuel expense was up $3 million over 2003 due to increased generation based on increased plant availability at Big Sandy in 2004 resulting from unplanned outages at Big Sandy in 2003.
o An increase in Depreciation and Amortization of $2 million in 2004 due to the implementation of emission control equipment at the Big Sandy plant in mid 2003.
o A $1 million increase in Other Operation expense primarily due to increased employee-related expenses in 2004.
o A $1 million decrease in gains from risk management activities included in Operating Income.

The decreases in Operating Income were partially offset by:

o An increase in retail revenues of $2 million over 2003 due to the rate increase in mid 2003 to recover the cost of emission control equipment.
o An increase in off-system sales and transmission revenues of $1 million.
o A decrease in Purchased Electricity from AEP Affiliates of $4 million due to increased purchases in 2003 driven by unplanned outages at the Big Sandy plant in 2003. In addition, energy purchases decreased from the Rockport Plant due to the planned outage at Rockport Unit 2 discussed above. Our energy purchases from Rockport are 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.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $3 million in the first quarter of 2004 compared to 2003 primarily due to favorable results from risk management activities for 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 Expenses increased $1 million due to a loss on the sale of land associated with the Ashland general office building in the first quarter of 2004.

Interest Charges increased $1 million primarily due to reduced allowance for funds used during construction in 2004 resulting from the completion of the emission control equipment in mid 2003.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
	-------	---	-----
Senior Unsecured Debt	Baa2	BBB	BBB

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2004.

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$15,490
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(2,407)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	246
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	1,399
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	2,380
Total MTM Risk Management Contract Net Assets	17,108
Net Cash Flow Hedge Contracts (f)	(1,003)
DETM Assignment (g)	(6,831)
Total MTM Risk Management Contract Net Assets at March 31, 2004	$9,274

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.
(f)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g)See Note 17 "Related Party Transactions" in the 2003 Annual Report.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(1,186)	$540	$(22)	$189	$-	$-	$(479)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	5,564	3,312	1,452	513	269	-	11,110
Prices Based on Models and Other Valuation Methods (b)	(27)	61	993	1,336	1,313	2,801	6,477
Total	$4,351	$3,913	$2,423	$2,038	$1,582	$2,801	$17,108

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2004

	Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$82	$338	$420
Changes in Fair Value (a)	(673)	-	(673)
Reclassifications from AOCI to Net Income (b)	(60)	(21)	(81)

Ending Balance March 31, 2004	$(651)	$317	$(334)

(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 $215 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$158	$498	$273	$139	$136	$527	$220	$52

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 $23 million and $29 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$106,901	$103,959
Sales to AEP Affiliates	6,612	8,135
TOTAL	113,513	112,094
OPERATING EXPENSES		
Fuel for Electric Generation	20,894	17,947
Purchased Electricity from AEP Affiliates	33,306	37,395
Other Operation	13,248	12,137
Maintenance	7,325	6,765
Depreciation and Amortization	10,859	8,712
Taxes Other Than Income Taxes	2,328	2,365
Income Taxes	6,460	6,939
TOTAL	94,420	92,260
OPERATING INCOME	19,093	19,834
Nonoperating Income (Loss)	952	(2,398)
Nonoperating Expenses	1,313	249
Nonoperating Income Tax Credit	(127)	(558)
Interest Charges	7,369	6,724
Income Before Cumulative Effect of Accounting Change	11,490	11,021
Cumulative Effect of Accounting Change (Net of Tax)	-	(1,134)
NET INCOME	$11,490	$9,887

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$50,450	$208,750	$48,269	$(9,451)	$298,018
Common Stock Dividends			(5,482)		(5,482)
TOTAL					292,536
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,865)	(2,865)
NET INCOME			9,887		9,887
TOTAL COMPREHENSIVE INCOME					7,022
MARCH 31, 2003	$50,450	$208,750	$52,674	$(12,316)	$299,558
DECEMBER 31, 2003	$50,450	$208,750	$64,151	$(6,213)	$317,138
Common Stock Dividends			(6,250)		(6,250)
TOTAL					310,888
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(754)	(754)
NET INCOME			11,490		11,490
TOTAL COMPREHENSIVE INCOME					10,736
MARCH 31, 2004	$50,450	$208,750	$69,391	$(6,967)	$321,624

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$458,081	$457,341
Transmission	381,584	381,354
Distribution	429,586	425,688
General	58,078	68,041
Construction Work in Progress	14,026	17,322
TOTAL	1,341,355	1,349,746
Accumulated Depreciation and Amortization	378,202	381,876
TOTAL - NET	963,153	967,870
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	5,421	5,423
Other Investments	806	1,022
TOTAL	6,227	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	1,234	886
Advances to Affiliates	13,142	-
Accounts Receivable:		
Customers	15,710	21,177
Affiliated Companies	20,237	25,327
Accrued Unbilled Revenues	7,083	5,534
Miscellaneous	287	97
Allowance for Uncollectible Accounts	(120)	(736)
Fuel	10,776	9,481
Materials and Supplies	20,610	16,585
Risk Management Assets	22,435	16,200
Margin Deposits	1,594	2,660
Prepayments and Other	1,866	1,696
TOTAL	114,854	98,907
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	101,799	99,828
Other Regulatory Assets	15,764	13,971
Long-term Risk Management Assets	22,269	16,134
Deferred Property Taxes	5,267	6,847
Other Deferred Charges	11,496	11,632
TOTAL	156,595	148,412
TOTAL ASSETS	$1,240,829	$1,221,634

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPATALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
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	69,391	64,151
Accumulated Other Comprehensive Income (Loss)	(6,967)	(6,213)
Total Common Shareholder's Equity	321,624	317,138
Long-term Debt:		
Nonaffiliated	427,625	427,602
Affiliated	80,000	60,000
Total Long-term Debt	507,625	487,602
TOTAL	829,249	804,740
CURRENT LIABILITIES		
Advances from Affiliates	-	38,096
Accounts Payable:		
General	23,162	22,802
Affiliated Companies	25,554	22,648
Customer Deposits	12,458	9,894
Taxes Accrued	12,356	7,329
Interest Accrued	8,886	6,915
Risk Management Liabilities	19,111	11,704
Obligations Under Capital Leases	1,650	1,743
Other	7,530	8,628
TOTAL	110,707	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	217,127	212,121
Regulatory Liabilities:		
Asset Removal Costs	28,204	26,140
Deferred Investment Tax Credits	7,662	7,955
Other Regulatory Liabilities	14,302	10,591
Long-term Risk Management Liabilities	16,319	12,363
Obligations Under Capital Leases	2,933	3,549
Deferred Credits and Other	14,326	14,416
TOTAL	300,873	287,135
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,240,829	$1,221,634

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$11,490	$9,887
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	1,134
Depreciation and Amortization	10,859	8,712
Deferred Income Taxes	3,442	2,766
Deferred Investment Tax Credits	(292)	(294)
Deferred Fuel Costs, Net	(988)	(388)
Loss on Sale of Assets	1,051	-
Mark-to-Market of Risk Management Contracts	(2,135)	3,500
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	8,202	5,776
Fuel, Materials and Supplies	(5,320)	(1,339)
Accounts Payable	3,266	(25,204)
Taxes Accrued	5,027	9,932
Change in Other Assets	(2,280)	(474)
Change in Other Liabilities	11,362	2,765
Net Cash Flows From Operating Activities	43,684	16,773
INVESTING ACTIVITIES		
Construction Expenditures	(7,386)	(35,025)
Proceeds from Sales of Property and Other	1,538	210
Net Cash Flow Used for Investing Activities	(5,848)	(34,815)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Affiliated	20,000	-
Change in Advances to/from Affiliates, Net	(51,238)	22,685
Dividends Paid	(6,250)	(5,482)
Net Cash Flows From (Used For) Financing Activities	(37,488)	17,203
Net Increase (Decrease) in Cash and Cash Equivalents	348	(839)
Cash and Cash Equivalents at Beginning of Period	886	2,304
Cash and Cash Equivalents at End of Period	$1,234	$1,465

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $5,104,000 and $7,975,000 and for income taxes was $(833,000) and $(6,435,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

Results of Operations

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.

Net Income decreased $114 million primarily due to a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003. Income Before Cumulative Effect increased $11 million primarily due to an increase in risk management income.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income increased $9 million for the three months ended March 31, 2004 compared with the three months ended March 31, 2003 due to:

o A $7 million increase in retail revenue primarily due to growth in the residential and commercial customer base.
o A $7 million increase in Sales to AEP Affiliates. The increase is primarily the result of a 19.0% increase in MWH for affiliated system sales partially offset by lower price realizations for this year. In addition, the increase in Sales to AEP Affiliates is also the result of optimizing our generation capacity and selling our excess generated power to the AEP Power Pool.
o A $7 million decrease in Purchased Electricity for Resale. This decrease was primarily due to cessation of the Buckeye Transmission agreement on June 30, 2003. Prior to this date, Ohio Edison interchange expenses were recorded in Purchased Electricity for Resale. An associated offsetting decrease in Ohio Edison revenue occurred in non-affiliated sales for resale; therefore, there was no effect to net income. In addition, the DOE Settlement Capacity Surcharge, which was included in rates for the first quarter of 2003, was no longer in effect for 2004.
o A $19 million decrease in Income Taxes. This decrease was primarily due to a decrease in pre-tax operating book income and tax adjustments recorded in 2003.

The increase in Operating Income was partially offset by:

o A $7 million decrease in non-affiliated sales for resale primarily as a result of a 13.4% decrease in MWH sales. In addition, there were no Ohio Edison interchange revenues recorded during 2004 as a result of the cessation of the Buckeye Transmission agreement discussed above with no effect to net income as a result of the cessation.
o A $13 million increase in Fuel for Electric Generation due to a
9.7% increase in the number of tons consumed during the first quarter of 2004. In addition, generation increased 11.1% from the first quarter of 2003 to the first quarter of 2004.
o A $10 million increase in Depreciation and Amortization primarily associated with the OPCo consolidation of JMG. Depreciation expense related to the assets owned by JMG are now consolidated with OPCo (there was no change in overall net income due to the consolidation of JMG). In addition, the increase is a result of a greater depreciable base in 2004, including capitalized software costs and the increased amortization of regulatory assets due to a federal tax adjustment which increased the regulatory asset amount and a corresponding quarterly adjustment to the amortization amount.

Other Impacts of Earnings

Nonoperating Income increased $20 million primarily due to favorable results from risk management activities in the first quarter of 2004 compared to losses that were incurred in the first quarter of 2003.

Nonoperating Income Tax Expense (Credit) increased $10 million as a result of an increase in pre-tax nonoperating book income.

Interest charges increased $11 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 long-term debt (there was no change in overall net income due to the consolidation of JMG).

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes during 2003 was due to the one-time after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A-
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the three months ended March 31, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$58,250	$5,285
Cash flows from (used for):		
Operating activities	125,431	35,390
Investing activities	(49,066)	(54,739)
Financing activities	(123,792)	46,476
Net increase (decrease) in cash and cash equivalents	(47,427)	27,127
Cash and cash equivalents at end of period	$10,823	$32,412

Operating Activities

Cash Flows From Operating Activities for the first quarter of 2004 increased $90 million compared to the first quarter of 2003. This is primarily due to significant reductions in Accounts Payable balances during the first quarter of 2003 partially associated with a wind-down of risk management activities in that year.

Investing Activities

Cash Flows Used For Investing Activities were reduced by $6 million during the first quarter of 2004 compared with the first quarter of 2003 due primarily to a decrease in construction expenditures.

Financing Activities

Cash Flows For Financing Activities used $124 million in the first quarter of 2004 and provided $46 million in the first quarter of 2003. This is primarily due to a decrease in the change in Advances to/from Affiliates, Net, during the first quarter of 2004 as a result of becoming a net lender as opposed to a net borrower.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2004 were:

Issuances

None

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$50,000	6.85	2004
Senior Unsecured Notes	140,000	7.375	2004
Notes Payable	1,500	6.27	2009
Notes Payable	1,463	6.81	2008

Other

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, own 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. Commercial operation of the Facility as required by the agreements between Juniper, AEP and The Dow Chemical Company (Dow) was achieved on March 18, 2004. The initial term of the lease commenced on March 18, 2004, and AEP may extend the lease term for up to 30 years. The lease of the Facility is reported by AEP as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on AEP's balance sheet.

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.

At March 31, 2004, Juniper's acquisition costs for the Facility totaled $516 million, and AEP estimates total costs for the completed Facility to be approximately $525 million. For the 30-year extended lease term, the majority of base lease rental is a variable rate obligation indexed to three-month LIBOR (1.11% as of March 31, 2004). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. 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 March 31, 2004 and December 31, 2003, AEP reflected $396 million as long-term debt due within one year. AEP's maximum required cash payment as a result of their 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 $516 million is greater than AEP's 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. Commercial operation for purposes of the PPA began April 2, 2004.

OPCo has 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 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, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. 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 argued that in the absence of mutually agreed upon protocols there were 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.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursuing against TEM and Tractebel SA under the guaranty damages and the full termination payment value of 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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$53,938
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(8,659)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	855
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	13,146
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	59,280
Net Cash Flow Hedge Contracts (f)	(3,474)
DETM Assignment (g)	(23,670)

Total MTM Risk Management Contracts Net Assets at March 31, 2004	$32,136

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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.
(f)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g)See Note 17 "Related Party Transactions" in the 2003 Annual Report.

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:

o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(4,109)	$1,873	$(75)	$654	$-	$-	$(1,657)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	19,279	11,476	5,033	1,779	931	-	38,498
Prices Based on Models and Other Valuation Methods (b)	(103)	212	3,443	4,632	4,551	9,704	22,439
Total	$15,067	$13,561	$8,401	$7,065	$5,482	$9,704	$59,280

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2004

	Power	Foreign Currency	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$268	$(371)	$(103)
Changes in Fair Value (a)	(2,306)	-	(2,306)
Reclassifications from AOCI to Net Income (b)	(219)	3	(216)
Ending Balance March 31, 2004	$(2,257)	$(368)	$(2,625)

(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 $1,058 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 the period indicated:

Three Months Ended March 31, 2004				Twelve Months Ended December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$546	$1,726	$945	$480	$444	$1,724	$722	$172

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 $161 million and $214 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$443,218	$450,887
Sales to AEP Affiliates	146,488	139,744
TOTAL	589,706	590,631
OPERATING EXPENSES		
Fuel for Electric Generation	166,271	153,648
Purchased Electricity for Resale	12,183	19,392
Purchased Electricity from AEP Affiliates	19,303	22,783
Other Operation	91,305	92,981
Maintenance	34,051	35,457
Depreciation and Amortization	71,782	61,551
Taxes Other Than Income Taxes	47,190	47,155
Income Taxes	39,982	58,794
TOTAL	482,067	491,761
OPERATING INCOME	107,639	98,870
Nonoperating Income (Loss)	16,930	(2,724)
Nonoperating Expenses	8,069	11,710
Nonoperating Income Tax Expense (Credit)	5,087	(4,656)
Interest Charges	31,969	20,742
Income Before Cumulative Effect of Accounting Changes	79,444	68,350
Cumulative Effect of Accounting Changes (Net of Tax)	-	124,632
NET INCOME	79,444	192,982
Preferred Stock Dividend Requirements	183	314
EARNINGS APPLICABLE TO COMMON STOCK	$79,261	$192,668

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$321,201	$462,483	$522,316	$(72,886)	$1,233,114
Common Stock Dividends			(41,934)		(41,934)
Preferred Stock Dividends			(314)		(314)
TOTAL					1,190,866
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(4,115)	(4,115)
NET INCOME			192,982		192,982
TOTAL COMPREHENSIVE INCOME					188,867
MARCH 31, 2003	$321,201	$462,483	$673,050	$(77,001)	$1,379,733
DECEMBER 31, 2003	$321,201	$462,484	$729,147	$(48,807)	$1,464,025
Common Stock Dividends			(57,057)		(57,057)
Preferred Stock Dividends			(183)		(183)
TOTAL					1,406,785
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,522)	(2,522)
Minimum Pension Liability				(3,942)	(3,942)
NET INCOME			79,444		79,444
TOTAL COMPREHENSIVE INCOME					72,980
MARCH 31, 2004	$321,201	$462,484	$751,351	$(55,271)	$1,479,765

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$4,047,851	$4,029,515
Transmission	948,046	938,805
Distribution	1,168,305	1,156,886
General	249,904	245,434
Construction Work in Progress	147,349	160,675
Total	6,561,455	6,531,315
Accumulated Depreciation and Amortization	2,515,726	2,485,947
TOTAL - NET	4,045,729	4,045,368
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	29,211	29,291
Other	22,774	24,264
TOTAL	51,985	53,555
CURRENT ASSETS		
Cash and Cash Equivalents	10,823	58,250
Advances to Affiliates, Net	139,888	67,918
Accounts Receivable:		
Customers	87,362	100,960
Affiliated Companies	145,088	120,532
Accrued Unbilled Revenues	18,895	17,221
Miscellaneous	1,374	736
Allowance for Uncollectible Accounts	(173)	(789)
Fuel	74,876	77,725
Materials and Supplies	102,631	92,136
Risk Management Assets	77,740	56,265
Margin Deposits	5,749	9,296
Prepayments and Other	16,836	15,883
TOTAL	681,089	616,133
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	170,020	169,605
Transition Regulatory Assets	287,903	310,035
Unamortized Loss on Reacquired Debt	11,305	10,172
Other	22,869	22,506
Long-term Risk Management Assets	77,163	52,825
Deferred Property Taxes	52,723	67,469
Deferred Charges and Other Assets	28,145	26,850
TOTAL	650,128	659,462
TOTAL ASSETS	$5,428,931	$5,374,518

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	462,484
Retained Earnings	751,351	729,147
Accumulated Other Comprehensive Income (Loss)	(55,271)	(48,807)
Total Common Shareholder's Equity	1,479,765	1,464,025
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,645	16,645
Total Shareholder's Equity	1,496,410	1,480,670
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	7,250
Long-term Debt:		
Nonaffiliated	1,605,905	1,608,086
Affiliated	200,000	-
Total Long-term Debt	1,805,905	1,608,086
TOTAL	3,307,315	3,096,006
Minority Interest	15,721	16,314
CURRENT LIABILITIES		
Short-term Debt - General	26,572	25,941
Long-term Debt Due Within One Year - Nonaffiliated	243,604	431,854
Accounts Payable:		
General	100,524	104,874
Affiliated Companies	84,434	101,758
Customer Deposits	27,588	17,308
Taxes Accrued	151,129	132,793
Interest Accrued	28,745	45,679
Risk Management Liabilities	66,220	38,318
Obligations Under Capital Leases	9,106	9,624
Other	59,721	71,642
TOTAL	797,643	979,791
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	938,218	933,582
Regulatory Liabilities:		
Asset Removal Costs	104,405	101,160
Deferred Investment Tax Credits	14,880	15,641
Other	-	3
Long-term Risk Management Liabilities	56,547	40,477
Deferred Credits	24,801	23,222
Obligations Under Capital Leases	22,672	25,064
Asset Retirement Obligations	43,489	42,656
Other	103,240	100,602
TOTAL	1,308,252	1,282,407
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,428,931	$5,374,518

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$79,444	$192,982
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(124,632)
Depreciation and Amortization	71,782	61,551
Deferred Income Taxes	7,701	(1,563)
Deferred Property Taxes	15,250	14,878
Mark-to-Market of Risk Management Contracts	(5,729)	14,156
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(13,886)	6,055
Fuel, Materials and Supplies	(7,646)	13,541
Prepayments and Other	2,594	(24,288)
Accounts Payable	(21,674)	(108,723)
Customer Deposits	10,280	7,025
Taxes Accrued	18,336	53,444
Interest Accrued	(16,934)	5,835
Change in Other Assets	(3,084)	(50,720)
Change in Other Liabilities	(11,003)	(24,151)
Net Cash Flows From Operating Activities	125,431	35,390
INVESTING ACTIVITIES		
Construction Expenditures	(50,188)	(56,372)
Proceeds from Sale of Property and Other	1,122	1,633
Net Cash Flows Used For Investing Activities	(49,066)	(54,739)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	494,375
Issuance of Long-term Debt - Affiliated	200,000	-
Change in Advances to/from Affiliates, Net	(71,970)	109,349
Change in Short-term Debt, Net	631	-
Change in Short-term Debt - Affiliates, Net	-	(275,000)
Retirement of Long-term Debt - Nonaffiliated	(192,963)	-
Retirement of Long-term Debt - Affiliated	-	(240,000)
Retirement of Cumulative Preferred Stock	(2,250)	-
Dividends Paid on Common Stock	(57,057)	(41,934)
Dividends Paid on Cumulative Preferred Stock	(183)	(314)
Net Cash Flows (Used For) From Financing Activities	(123,792)	46,476
Net Increase (Decrease) in Cash and Cash Equivalents	(47,427)	27,127
Cash and Cash Equivalents at Beginning of Period	58,250	5,285
Cash and Cash Equivalents at End of Period	$10,823	$32,412

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $46,636,000 and $14,551,000 and for income taxes was $(8,664,000) and $(22,475,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

Results of Operations

Net Income decreased $10 million for the quarter due mainly to increased Other Operation expenses.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues due to the functioning of the fuel adjustment clause in Oklahoma.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income decreased $13 million primarily due to:

o Decreased non-fuel related revenues of $3 million, due mainly to a $2 million decrease in wholesale margins from decreased off-system KWH sales.
o Increased Other Operation expenses of $12 million due mainly to increased affiliated ancillary services and OATT resulting from an adjustment for prior years due to revised data from ERCOT for the years 2001-2003 of $5 million, other transmission related expenses, increased administrative expenses largely due to outside services and employee related expenses.
o Increased Maintenance expense of $4 million due mainly to increased scheduled power plant maintenance of $3 million. . The decrease in Operating Income was partially offset by:

o Decreased income taxes of $7 million is due primarily to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Interest Charges decreased $3 million as a result of the replacement of higher interest rate first mortgage bonds in 2003 with lower fixed-rate senior unsecured debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2004.

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$14,057
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,039)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	109
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(9,099)
Total MTM Risk Management Contract Net Assets	4,028
Net Cash Flow Hedge Contracts (f)	(442)
Total MTM Risk Management Contract Net Assets at March 31, 2004	$3,586

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d)"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.
(e)"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 Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(f) "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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

Remainder After

	2004	2005	2006	2007	2008	2008	Total (c)
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(523)	$238	$(10)	$83	$-	$-	$(212)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,850	1,140	29	-	-	-	3,019
Prices Based on Models and Other Valuation Methods (b)	(66)	(128)	85	215	335	780	1,221
Total	$1,261	$1,250	$104	$298	$335	$780	$4,028

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Three Months Ended March 31, 2004

	(in thousands)
Beginning Balance December 31, 2003	$156
Changes in Fair Value (a)	(416)
Reclassifications from AOCI to Net Income (b)	(28)
Ending Balance March 31, 2004	$(288)

(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 $133 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 the period indicated:

Three Months Ended Twelve Months Ended

March 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$70	$220	$120	$61	$258	$1,004	$420	$100

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 $56 million and $66 million at March 31, 2004 and December 31, 2003, 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.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$204,043	$238,267
Sales to AEP Affiliates	3,142	4,395
TOTAL	207,185	242,662
OPERATING EXPENSES		
Fuel for Electric Generation	89,085	103,174
Purchased Electricity for Resale	9,168	12,491
Purchased Electricity from AEP Affiliates	26,899	42,107
Other Operation	43,676	31,618
Maintenance	13,122	9,394
Depreciation and Amortization	22,176	21,494
Taxes Other Than Income Taxes	9,817	9,646
Income Taxes (Credits)	(7,333)	(408)
TOTAL	206,610	229,516
OPERATING INCOME	575	13,146
Nonoperating Income	244	650
Nonoperating Expense	542	439
Nonoperating Income Tax Credit	392	200
Interest Charges	9,953	12,866
NET INCOME (LOSS)	(9,284)	691
Preferred Stock Dividend Requirements	53	53
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$(9,337)	$638

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$157,230	$180,016	$116,474	$(54,473)	$399,247
Common Stock Dividends			(7,500)		(7,500)
Preferred Stock Dividends			(53)		(53)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent			(548)		(548)
TOTAL					391,146
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,197)	(1,197)
Minimum Pension Liability				(58)	(58)
NET INCOME			691		691
TOTAL COMPREHENSIVE INCOME (LOSS)					(564)
MARCH 31, 2003	$157,230	$180,016	$109,064	$(55,728)	$390,582
DECEMBER 31, 2003	$157,230	$230,016	$139,604	$(43,842)	$483,008
Common Stock Dividends			(8,750)		(8,750)
Preferred Stock Dividends			(53)		(53)
TOTAL					474,205
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(444)	(444)
NET LOSS			(9,284)		(9,284)
TOTAL COMPREHENSIVE INCOME (LOSS)					(9,728)
MARCH 31, 2004	$157,230	$230,016	$121,517	$(44,286)	$464,477

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,067,554	$1,065,408
Transmission	451,920	451,292
Distribution	1,054,116	1,031,229
General	206,951	203,756
Construction Work in Progress	35,041	54,711
TOTAL	2,815,582	2,806,396
Accumulated Depreciation and Amortization	1,082,327	1,069,216
TOTAL - NET	1,733,255	1,737,180
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,388	4,631
Other Investments	2,320	2,320
TOTAL	6,708	6,951
CURRENT ASSETS		
Cash and Cash Equivalents	8,918	14,258
Accounts Receivable:		
Customers	27,280	28,515
Affiliated Companies	15,845	19,852
Miscellaneous	1,189	-
Allowance for Uncollectible Accounts	(38)	(37)
Fuel Inventory	16,770	18,331
Materials and Supplies	39,064	38,125
Regulatory Asset for Under-recovered Fuel Costs	19,772	24,170
Risk Management Assets	6,422	18,586
Margin Deposits	3,936	4,351
Prepayments and Other	3,444	2,655
TOTAL	142,602	168,806
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	13,885	14,357
Other	13,044	14,342
Long-term Risk Management Assets	4,418	10,379
Deferred Charges	43,801	18,017
TOTAL	75,148	57,095
TOTAL ASSETS	$1,957,713	$1,970,032

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	230,016
Retained Earnings	121,517	139,604
Accumulated Other Comprehensive Income (Loss)	(44,286)	(43,842)
Total Common Shareholder's Equity	464,477	483,008
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,267	5,267
Total Shareholder's Equity	469,744	488,275
Long-term Debt	413,314	490,598
TOTAL	883,058	978,873
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	161,020	83,700
Advances from Affiliates	47,642	32,864
Accounts Payable:		
General	46,203	48,808
Affiliated Companies	52,071	57,206
Customer Deposits	28,904	26,547
Taxes Accrued	44,581	27,157
Interest Accrued	3,738	3,706
Risk Management Liabilities	4,906	11,067
Obligations Under Capital Leases	464	452
Other	30,661	35,234
TOTAL	420,190	326,741
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	335,348	335,434
Long-Term Risk Management Liabilities	2,348	3,602
Regulatory Liabilities:		
Asset Removal Costs	216,517	214,033
Deferred Investment Tax Credits	29,963	30,411
SFAS 109 Regulatory Liability, Net	24,296	24,937
Other	5,508	15,406
Obligations Under Capital Leases	576	558
Deferred Credits and Other	39,909	40,037
TOTAL	654,465	664,418
Commitments and Contingencies (Note 5)		
	$1,957,713	$1,970,032

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income (Loss)	$(9,284)	$691
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	22,176	21,494
Deferred Income Taxes	456	1,309
Deferred Investment Tax Credits	(448)	(447)
Deferred Property Taxes	(25,943)	(24,413)
Mark-to-Market of Risk Management Contracts	10,029	(1,412)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	4,054	(769)
Fuel, Materials and Supplies	622	229
Accounts Payable	(7,740)	(4,822)
Taxes Accrued	17,424	15,878
Fuel Recovery	4,398	(1,231)
Changes in Other Assets	(2,115)	(6,590)
Changes in Other Liabilities	(10,604)	(9,266)
Net Cash Flows From (Used For) Operating Activities	3,025	(9,349)
INVESTING ACTIVITIES		
Construction Expenditures	(14,584)	(17,612)
Proceeds from Sale of Property and Other	244	-
Net Cash Flows Used For Investing Activities	(14,340)	(17,612)
FINANCING ACTIVITIES		
Change in Advances to/from Affiliates, Net	14,778	33,715
Dividends Paid on Common Stock	(8,750)	(7,500)
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Net Cash Flows From Financing Activities	5,975	26,162
Net Decrease in Cash and Cash Equivalents	(5,340)	(799)
Cash and Cash Equivalents at Beginning of Period	14,258	16,774
Cash and Cash Equivalents at End of Period	$8,918	$15,975

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $8,951,000 and $9,653,000 and for income taxes was $(2,695,000) and $(959,000) in 2004 and 2003, 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
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to PSO's 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.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Net Income decreased $14 million for 2004 due largely to the $9 million (net of tax) Cumulative Effect of Accounting Changes recorded in 2003.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues and/or operations expense due to the functioning of the fuel adjustment clauses in the states in which we serve.

First Quarter 2004 Compared to First Quarter 2003

Operating Income

Operating Income decreased by $6 million primarily due to:

o A decrease in risk management activities of $4 million.
o Increased Other Operations expense of $12 million primarily due to an increase related to transmission expense resulting from a prior year true-up for OATT transactions recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003 of $6 million and a $5 million increase related to deferred fuel for the Louisiana jurisdiction.
o Increased Maintenance expense of $3 million primarily related to scheduled power plant maintenance offset in part by lower overhead line expense.
o Increased Depreciation and Amortization expense of $3 million due primarily to the restoration in 2003 of a regulatory asset related to the recovery of fuel related costs in Arkansas.

The decrease in Operating Income was partially offset by:

o An increase in retail base revenues of $4 million due to an increased number of customers and their average usage, offset in part by milder weather resulting from a 3% decrease in degree-days.
o A $2 million increase in transmission revenues due mainly to a prior year true-up for OATT transactions recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003.
o Decreased Income Taxes of $5 million is due primarily to a decrease in pre-tax operating book income.

Other Impacts on Earnings

Minority Interest Expense of $1 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to implementation of FIN 46.

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 and EITF 02-3 in 2003.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Cash Flow

Cash flows for the Three Months ended March 31, 2004 and 2003 were as follows:

	2004	2003
Cash and cash equivalents at beginning of period	$11,724	$2,069
Cash flows from (used for):		
Operating activities	17,180	24,334
Investing activities	(19,664)	(25,418)
Financing activities	56,959	6,178
Net increase (decrease) in cash and cash equivalents	54,475	5,094
Cash and cash equivalents at end of period	$66,199	$7,163

Operating Activities

Cash Flows From Operating Activities were $17 million primarily due to Net Income, Accounts Receivables, Fuel Recovery and Taxes Accrued.

Investing Activities

Cash Used for Investing Activities was primarily related to construction projects for improved transmission and distribution service reliability.

Financing Activities

Cash Flows From Financing Activities through long-term debt issuances and advances from affiliates were used to replace higher interest rate long-term debt with lower interest rate long-term debt.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2004 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$53,500	Variable	2019

In the second quarter of 2004, the funds from the issuance of the installment purchase contracts were used to redeem the $53.5 million, 7.60% DeSoto installment purchase contracts due 2019.

Retirements

Principal Interest Due

Type of Debt	Amount (in thousands)	Rate (%)	Date
First Mortgage Bonds	$80,000	6.875	2025
Installment Purchase Contracts	450	6.0	2008
Notes Payable	1,707	4.47	2011
Notes Payable	750	Variable	2008

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.

Critical Accounting Policies

See "Critical Accounting Policies" in "Registrants' Combined Management's Discussion and Analysis" in the 2003 Annual Report for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, the accounting for pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about 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
Three Months Ended March 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$16,606
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(3,297)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	128
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	(1,750)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(6,920)

Total MTM Risk Management Contract Net Assets	4,767
Net Cash Flow Hedge Contracts (f)	(1,557)

Total MTM Risk Management Contract Net Assets at March 31, 2004	

$3,210

========

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 that were entered into prior to 2004.
(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 2004. 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 2004.
(d) "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.
(e) "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.
(f) "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:
o The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
o 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 March 31, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted - Exchange Traded Contracts	$(616)	$281	$(11)	$98	$-	$-	$(248)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,178	1,342	34	(1)	-	-	3,553
Prices Based on Models and Other Valuation Methods (b)	(51)	(150)	99	253	394	917	1,462
Total	$1,511	$1,473	$122	$350	$394	$917	$4,767

(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. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, the table does not provide a full picture of our hedging activity. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Three Months Ended March 31, 2004

	(in thousands)
Beginning Balance December 31, 2003	$184
Changes in Fair Value (a)	(490)
Reclassifications from AOCI to Net Income (b)	(32)
Ending Balance March 31, 2004	$(338)

(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 $156 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 the period indicated:

Three Months Ended March 31, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$82	$259	$142	$72	$304	$1,182	$495	$118

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 $37 million and $57 million at March 31, 2004 and December 31, 2003, 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 Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$213,949	$223,614
Sales to AEP Affiliates	22,211	31,664
TOTAL	236,160	255,278
OPERATING EXPENSES		
Fuel for Electric Generation	86,738	103,010
Purchased Electricity for Resale	5,934	12,567
Purchased Electricity from AEP Affiliates	7,307	10,810
Other Operation	52,644	40,857
Maintenance	15,648	12,817
Depreciation and Amortization	31,285	28,035
Taxes Other Than Income Taxes	16,567	15,873
Income Taxes	131	5,265
TOTAL	216,254	229,234
OPERATING INCOME	19,906	26,044
Nonoperating Income	1,403	872
Nonoperating Expenses	826	521
Nonoperating Income Tax Expense (Credit)	(356)	50
Interest Charges	15,228	15,854
Minority Interest	(881)	-
Income Before Cumulative Effect of Accounting Changes	4,730	10,491
Cumulative Effect of Accounting Changes (Net of Tax)	-	8,517
NET INCOME	4,730	19,008
Preferred Stock Dividend Requirements	57	57
EARNINGS APPLICABLE TO COMMON STOCK	$4,673	$18,951

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 Three Months Ended March 31, 2004 and 2003
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2002	$135,660	$245,003	$334,789	$(53,683)	$661,769
Common Stock Dividends			(18,199)		(18,199)
Preferred Stock Dividends			(57)		(57)
TOTAL					643,513
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,367)	(1,367)
NET INCOME			19,008		19,008
TOTAL COMPREHENSIVE INCOME					17,641
MARCH 31, 2003	$135,660	$245,003	$335,541	$(55,050)	$661,154
DECEMBER 31, 2003	$135,660	$245,003	$359,907	$(43,910)	$696,660
Common Stock Dividends			(15,000)		(15,000)
Preferred Stock Dividends			(57)		(57)
TOTAL					681,603
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(522)	(522)
Minimum Pension Liability				23,066	23,066
NET INCOME			4,730		4,730
TOTAL COMPREHENSIVE INCOME					27,274
MARCH 31, 2004	$135,660	$245,003	$349,580	$(21,366)	$708,877

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,628,532	$1,622,498
Transmission	616,091	615,158
Distribution	1,087,546	1,078,368
General	427,318	423,427
Construction Work in Progress	52,296	60,009
TOTAL	3,811,783	3,799,460
Accumulated Depreciation and Amortization	1,641,071	1,617,846
TOTAL - NET	2,170,712	2,181,614
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	3,808	3,808
Other Investments	4,710	4,710
TOTAL	8,518	8,518
CURRENT ASSETS		
Cash and Cash Equivalents	66,199	11,724
Advances to Affiliates	-	66,476
Accounts Receivable:		
Customers	38,049	41,474
Affiliated Companies	26,695	10,394
Miscellaneous	4,697	4,682
Allowance for Uncollectible Accounts	(2,089)	(2,093)
Fuel Inventory	58,306	63,881
Materials and Supplies	33,139	33,775
Regulatory Asset for Under-recovered Fuel Costs	8,396	11,394
Risk Management Assets	8,392	19,715
Margin Deposits	4,634	5,123
Prepayments and Other	19,059	19,078
TOTAL	265,477	285,623
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	4,232	3,235
Unamortized Loss on Required Debt	21,891	19,331
Minimum Pension Liability	35,486	-
Other	14,278	15,859
Long-term Risk Management Assets	5,203	12,178
Deferred Charges	81,428	55,605
TOTAL	162,518	106,208
TOTAL ASSETS	$2,607,225	$2,581,963

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(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	349,580	359,907
Accumulated Other Comprehensive Income (Loss)	(21,366)	(43,910)
Total Common Shareholder's Equity	708,877	696,660
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholder's Equity	713,577	701,360
Long-term Debt	710,765	741,594
TOTAL	1,424,342	1,442,954
Minority Interest	1,159	1,367
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	144,609	142,714
Advances from Affiliates	36,268	-
Accounts Payable:		
General	30,772	37,646
Affiliated Companies	28,422	35,138
Customer Deposits	26,392	24,260
Taxes Accrued	68,373	28,691
Interest Accrued	14,253	16,852
Risk Management Liabilities	7,186	11,361
Obligations Under Capital Leases	3,299	3,159
Regulatory Liability for Over-recovered Fuel	10,829	4,178
Other	30,098	53,753
TOTAL	400,501	357,752
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	357,013	349,064
Long-term Risk Management Liabilities	3,199	4,667
Reclamation Reserve	14,534	16,512
Regulatory Liabilities:		
Asset Removal Costs	240,044	236,409
Deferred Investment Tax Credits	38,783	39,864
Excess Earnings	2,600	2,600
Other	10,228	18,779
Asset Retirement Obligations	8,628	8,429
Obligations Under Capital Leases	18,318	18,383
Deferred Credits and Other	87,876	85,183
TOTAL	781,223	779,890
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,607,225	$2,581,963

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$4,730	$19,008
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	31,285	28,035
Deferred Income Taxes	(5,182)	(4,034)
Deferred Investment Tax Credits	(1,081)	(1,081)
Deferred Property Taxes	(29,063)	(27,945)
Cumulative Effect of Accounting Changes	-	(8,517)
Mark-to-Market of Risk Management Contracts	11,837	(1,462)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(12,895)	(1,288)
Fuel, Materials and Supplies	6,211	2,660
Accounts Payable	(13,590)	(17,294)
Taxes Accrued	39,682	41,182
Fuel Recovery	9,649	2,729
Change in Other Assets	(33,109)	1,461
Change in Other Liabilities	8,706	(9,120)
Net Cash Flows From Operating Activities	17,180	24,334
INVESTING ACTIVITIES		
Construction Expenditures	(19,664)	(25,702)
Proceeds from Sale of Assets and Other	-	284
Net Cash Flows Used For Investing Activities	(19,664)	(25,418)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	52,179	-
Retirement of Long-term Debt	(82,907)	(55,450)
Change in Advances to/from Affiliates, Net	102,744	79,884
Dividends Paid on Common Stock	(15,000)	(18,199)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows From Financing Activities	56,959	6,178
Net Increase in Cash and Cash Equivalents	54,475	5,094
Cash and Cash Equivalents at Beginning of Period	11,724	2,069
Cash and Cash Equivalents at End of Period	$66,199	$7,163

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $15,964,000 and $17,963,000 and for income taxes was $(2,228,000) and $(755,000) in 2004 and 2003, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

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.

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.	Significant Accounting Matters	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
4.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
5.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
7.	Assets Held for Sale	TCC
8.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Financing Activities	APCo, KPCo, OPCo, SWEPCo, TCC, TNC

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2003 Annual Report as incorporated in and filed with our 2003 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments which are necessary for a fair presentation of the results of operations for interim periods.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. The components of Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries is shown in the following table.

Components	March 31, 2004	December 31, 2003
	(in thousands)	
Cash Flow Hedges:		
APCo	$(4,619)	$(1,569)
CSPCo	(1,707)	202
I&M	(1,871)	222
KPCo	(335)	420
OPCo	(2,625)	(103)
PSO	(287)	156
SWEPCo	(338)	184
TCC	(15,590)	(1,828)
TNC	(5,211)	(601)
Minimum Pension Liability:		
APCo	$(50,519)	$(50,519)
CSPCo	(46,529)	(46,529)
I&M	(25,328)	(25,328)
KPCo	(6,633)	(6,633)
OPCo	(52,646)	(48,704)
PSO	(43,998)	(43,998)
SWEPCo	(21,027)	(44,094)
TCC	(62,511)	(60,044)
TNC	(26,117)	(26,117)

During the first quarter of 2004, SWEPCo reclassified $23 million from Accumulated Other Comprehensive Income (Loss) related to minimum pension liability to Regulatory Assets ($35 million) and Deferred Income Taxes ($12 million) as a result of authoritative letters issued by the FERC and the Arkansas and Louisiana commissions.

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.

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:

	Balance At January 1, 2004	Accretion	Balance at March 31, 2004
		(in millions)	
AEGCo (a)	$1.1	$-	$1.1
APCo (a)	21.7	0.5	22.2
CSPCo (a)	8.7	0.2	8.9
I&M (b)	553.2	9.7	562.9
OPCo (a)	42.7	0.8	43.5
SWEPCo (d)	8.4	0.2	8.6
TCC (c)	218.8	4.0	222.8

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.1 million at March 31, 2004) and nuclear decommissioning costs for the Cook Plant ($561.8 million at March 31, 2004).
(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.

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of March 31, 2004 and December 31 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $897 million ($767 million for I&M and $130 million for TCC) and $845 million ($720 million for I&M and $125 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.

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.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

We implemented FIN 46R, "Consolidation of Variable Interest Entities," effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which 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.

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

In accordance with FASB Staff Position No. 106-1, in December 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC elected to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) until the FASB issues authoritative guidance on the accounting for the federal subsidy. The measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in the 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 their results of operations or financial condition.
Future Accounting Changes

The Financial Accounting Standards Board's (FASB's) standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on projects related to accounting for stock compensation, pension plans, property, plant and equipment, earnings per share calculations and related tax impacts. We also expect to see more projects as a result of the FASB's desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in the 2003 Annual Report, rate proceedings in the FERC and several state jurisdictions are ongoing. The Rate Matters note within the 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending, without significant changes since year-end. The following sections discuss current activities.

TNC Fuel Reconciliation - Affecting TNC

In 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 as of the end of the reconciliation period. 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 remand 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. 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.

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 received a written order in March 2004 and increased the reserve by $1.5 million. In March 2004, various parties, including TNC, requested a rehearing of the PUCT's ruling.

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 was appealed to the Third Court of Appeals. In March 2004, the Third Court of Appeals heard oral arguments. A decision is pending.

TCC Fuel Reconciliation - Affecting TCC

In 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. 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. Based on an analysis of the ALJ's recommendations, TCC established an additional reserve of $13 million during the first quarter of 2004. The over-recovery balance and the provisions total $163 million including interest at March 31, 2004. 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 4 "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. 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 we achieve future cost savings. In April 2004, the PUCT approved the settlement.

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. The PUCT held hearings in March 2004 and is expected to issue a decision in June 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 Compliance Filing - Affecting SWEPCo

In October 2002, SWEPCo filed with the Louisiana Public Service Commission (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. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicate that SWEPCo's current rates should not be reduced. 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.

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 Corporation Commission of the State of Oklahoma (OCC) seeking recovery of the $44 million over an 18-month 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. An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested $8.8 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated trading margins were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and could more than offset the $44 million 2002 allocation. The intervenor and the OCC Staff also believed trading margins were allocated incorrectly. Under the intervenor's recalculation of margin allocation, PSO's amount of recoverable fuel would be decreased approximately $6.8 million for 2000 and $10.7 million for 2001. OCC Staff calculates the 2001 amount at $8.8 million. They also recommend recalculation of fuel for years subsequent to 2001 using the same methods. Hearings are scheduled to occur in June 2004. Management believes that fuel costs have been prudently incurred consistent with OCC rules, and that the allocation of trading margins pursuant to the agreements is correct. 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.

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

$31 million of RTO formation and integration costs and related carrying charges through March 31, 2004. Amounts per company are as follows:

Company	(in millions)
APCo	$8.5
CSPCo	3.6
I&M	6.6
KPCo	2.0
OPCo	9.4

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 plan to 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. 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. The AEP East companies are scheduled to join PJM in October 2004, although there are pending proceedings at the FERC and in Virginia and Kentucky concerning our integration into PJM. Therefore, 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 AEP's share of 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. A hearing for this proceeding is scheduled in July 2004.

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. In April 2004, we reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC is expected to consider the agreement in May.

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 205(a) apply. The FERC ALJ affirmed the FERC's preliminary finding in March 2004. The FERC has not issued a final order in this matter.

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 Independent System Operator (ISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners 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.

In November 2003, the FERC adopted a new regional rate design and 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 was expected to implement a new rate design after the two-year period. As required by the FERC, AEP filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. Various parties raised issues with the SECA rate orders and the FERC implemented settlement procedures before an ALJ.

In March 2004, the FERC approved a settlement that delays elimination of T&O rates until December 1, 2004 and provides principles and procedures for a new rate design for the RTO Footprint, to be effective on December 1, 2004. The settlement also provides that if the process does not result in the implementation of a new rate design on December 1, then the SECA rates will be implemented and will remain in effect until a new rate is implemented by the FERC. If implemented, the SECA rate would not be effective beyond March 31, 2006. The AEP East companies received approximately $157 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended December 31, 2003. At this time, management is unable to predict whether the new rate design will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on 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. The Cook settlement agreement provided for the fixed rate to end in February 2004. In another agreement in connection with a planned corporate separation I&M agreed, contingent on implementing the corporate separation, to a new freeze conditionally beginning March 2004 and continuing through December 2007.

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 after March 1, 2004. Negotiations with the parties to determine a resolution of this issue are ongoing. The IURC ordered the fixed fuel adjustment charge remain in place, on an interim basis, for March and April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor for May through September 2004, subject to true-up following the resolution of issues in the corporate separation agreement. The IURC also issued an order that reopens the corporate separation docket to investigate issues related to the corporate separation agreement.

Michigan 2004 Fuel Recovery Plan - Affecting I&M

A Michigan Public Service Commission's (MPSC) 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. A public hearing of this case occurred on March 10, 2004 and a MPSC order is expected during the second half of 2004. 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 MPSC order.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in the 2003 Annual Report, certain AEP subsidiaries are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in the 2003 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring.

OHIO RESTRUCTURING - Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (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 Public Utilities Commission of Ohio (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 was 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. 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 charges on required expenditures. Management cannot predict whether the plan will be approved as submitted or its impact on results of operations 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 March 31, 2004, CSPCo has incurred $33 million and deferred $13 million and OPCo has incurred $36 million and deferred $16 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:
o provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
o requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;

o provides for an earnings test for each of the years 1999 through 2001 and;
o 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.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:
o net stranded generation plant costs and generation-related regulatory assets (stranded costs),
o a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up),
o final approved deferred fuel balance,
o unrefunded accumulated excess earnings,
o excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
o 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 generation 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 TCC's generation assets for stranded cost purposes. When completed, the sale of TCC's 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 generation 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 generation 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 hired a consultant to advise the PUCT and TCC during the sale of the generation assets. TCC's sale of its generation 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 generation plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to unaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices, expiring in May and June 2004, to the co-owners of Oklaunion and STP, respectively. TCC filed for FERC approval of the sales of the fossil and hydro plants. TCC will request approval of the STP sale from the FERC during the second quarter of 2004. TCC received a notice from a co-owner of Oklaunion exercising their right of first refusal; therefore, SEC approval will be required. Approval of the sale of STP from the Nuclear Regulatory Commission is required. The completion of the sales is expected to occur in 2004, subject to rights of first refusal and the necessary approvals required for each sale. TCC will file its 2004 true-up proceeding with the PUCT after the sale of the generation assets.

After the 2004 true-up proceeding, TCC may recover stranded costs and other true-up amounts through transmission and distribution rates as a competition transition and may seek to issue securitization revenue bonds for its stranded costs. The cost of the securitization bonds is recovered through transmission and distribution rates as a separate transition charge. TCC recorded an impairment of generation assets of $938 million in December 2003 as a regulatory asset (see Note 7). 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 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 auction true-up 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. TNC received a written order on March 1, 2004 that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $4.6 million. This balance will be included in TNC's 2004 true-up proceeding. Various parties, including TNC, requested rehearing of the PUCT's order.

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 3 "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. The District Court remanded to the PUCT an appeal of the same issue from the PUCT's 2001 order to be consistent with the Court of Appeals decision. 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.

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 price-to-beat (PTB) retail electric providers (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 March 31, 2004, the remaining retail clawback liability was $45.5 million for TCC and $11.8 million for TNC.

Stranded Cost Recovery

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.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation which extends the transition period for electricity restructuring including capped rates through December 31, 2010. The legislation provides specific cost recovery opportunities during the capped rate period, including two general rate changes and an opportunity for recovery of incremental environmental and reliability costs.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within the 2003 Annual Report, certain AEP subsidiaries continue to be involved in various legal matters. The 2003 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since their disclosure in the 2003 Annual Report. The material matters discussed in the 2003 Annual Report without significant changes in status since year-end include, but are not limited to, (1) nuclear matters, (2) construction commitments, (3) merger litigation, (4) Texas Commercial Energy, LLP lawsuit, and (5) FERC proposed Standard Market Design. See disclosure below for significant matters with changes in status subsequent to the disclosure made in the 2003 Annual Report.

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 new source review requirements of the Clean Air Act (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 CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 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 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 requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals, and the District Court denied the Federal EPA's motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that obviated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice.

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 CAA 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 CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court, and on May 3, 2004, that petition was denied.

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 a prospective effect, and was to 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.

OPERATIONAL

Power Generation Facility - Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, own 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. Commercial operation of the Facility as required by the agreements between Juniper, AEP and The Dow Chemical Company (Dow) was achieved on March 18, 2004.

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. Commercial operation for purposes of the PPA began April 2, 2004.

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 and 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 argued that in the absence of mutually agreed upon protocols there were 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.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursing against TEM and Tractebel SA under the guaranty damages and the full termination payment value of the PPA.

Enron Bankruptcy - Affecting APCo, CSPCo, I&M, KPCo and OPCo

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

Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. The AEP subsidiaries asserted their 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.

Enron bankruptcy summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

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.

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 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. In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. AEP and two unaffiliated utilities were required to submit generation market power analyses within sixty days of the FERC's order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. Management is unable to predict the outcome of these actions by the FERC or their affect on future results of operations and cash flows.

6. 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.

Letter of Credit

TCC has entered into a standby letter of credit (LOC) with third parties. This LOC covers credit enhancements for issued bonds. This LOC was issued in TCC's ordinary course of business. At March 31, 2004, the maximum future payments of the LOC are $43 million which matures November 2005. AEP holds all assets of the subsidiary as collateral. There is no recourse to third parties in the event this letter of credit is 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 $51 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 March 31, 2004, 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. 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 March 31, 2004, 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
Subsidiary	(in millions)
APCo	$1
CSPCo	1
I&M	2
KPCo	1
OPCo	4
PSO	4
SWEPCo	4
TCC	6
TNC	2

7. ASSETS HELD FOR SALE

DISPOSITIONS ANNOUNCED DURING FIRST QUARTER 2004

During the first quarter of 2004 we announced the following dispositions expected to close later this year:

Texas Plants

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as "reliability must run" status. During 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.

During early 2004 TCC signed agreements to sell all of its generating assets at prices which approximate book value after considering the impairment charge described above. As a result, TCC does not expect these pending asset sales, described below, to have a significant effect on its future results of operations.

Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.8 percent share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments. The planned sale is expected to close in June 2004, subject to the co-owners' decisions on their rights of first refusal. TCC has received notice from a co-owner of their decision to exercise their right of first refusal.

South Texas Project

In February 2004, TCC signed an agreement to sell its 25.2 percent share of the South Texas Project (STP) nuclear plant for approximately $333 million, subject to closing adjustments. TCC expects the sale to close in the second half of 2004, subject to the co-owners' decisions on their rights of first refusal. TCC does not expect the sale of this asset to have a significant effect on its results of operations.

TCC Generation Assets

In March 2004, TCC signed an agreement to sell its remaining generating assets, including eight natural gas plants, one coal-fired plant and one hydro plant to a non-related joint venture for approximately $430 million, subject to closing adjustments. TCC expects the sale to close in mid-2004, subject to various regulatory approvals and clearances.

ASSETS HELD FOR SALE

The assets and liabilities of the TCC plants held for sale at March 31, 2004 and December 31, 2003 are as follows:

	March 31, 2004	December 31, 2003
	(in millions)	
Assets:		
Current Assets	$56	$57
Property, Plant and Equipment, Net	799	797
Regulatory Assets	48	49
Decommissioning Trusts	130	125
Total Assets Held for Sale	$1,033	$1,028
Liabilities:		
Regulatory Liabilities	$9	$9
Asset Retirement Obligations	223	219
Total Liabilities Held for Sale	$232	$228

8. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, 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 table provides the components of AEP's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003

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		(in millions)		
Service Cost	$22	$20	$11	$11
Interest Cost	57	58	33	32
Expected Return on Plan Assets	(73)	(79)	(21)	(16)
Amortization of Transition (Asset) Obligation	-	(2)	7	7
Amortization of Net Actuarial Loss	4	2	12	13
Net Periodic Benefit Cost (Credit)	$10	$(1)	$42	$47

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for the three months ended March 31, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
		(in thousands)		
APCo	$322	$(1,301)	$7,767	$8,438
CSPCo	(404)	(1,350)	3,367	3,671
I&M	1,118	(203)	5,227	5,750
KPCo	144	(142)	913	1,010
OPCo	(28)	(1,656)	6,373	7,036
PSO	713	(74)	2,492	2,471
SWEPCo	914	254	2,492	2,566
TCC	766	(30)	2.997	3,238
TNC	344	151	1,262	1,468

9. 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.

10. FINANCING ACTIVITIES

Long-term debt and other securities issuances and retirements during the first three months of 2004 were:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Issuances:				
SWEPCo	Installment Purchase Contracts	$53,500	Variable	2019

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements:				
APCo	Installment Purchase Contracts	$40,000	5.45	2019
OPCo	Installment Purchase Contracts	50,000	6.85	2022
OPCo	Senior Unsecured Notes	140,000	7.375	2038
OPCo	Notes Payable	1,500	6.27	2009
OPCo	Notes Payable	1,463	6.81	2008
SWEPCo	First Mortgage Bonds	80,000	6.875	2025
SWEPCo	Installment Purchase Contracts	450	6.0	2008
SWEPCo	Notes Payable	1,707	4.47	2011
SWEPCo	Notes Payable	750	Variable	2008
TCC	First Mortgage Bonds	1,055	7.125	2005
TCC	Securitization Bonds	28,809	3.54	2005
TNC	First Mortgage Bonds	24,036	6.125	2004

In addition to the transactions reported in the table above, the following table lists intercompany issuances and retirements of debt due to AEP:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
KPCo	Notes Payable	$20,000	5.25	2015
OPCo	Notes Payable	200,000	5.25	2015

Retirements:

None

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, SWEPCo, TCC and TNC (domestic utility companies). The following are the SEC authorized limits for short-term borrowings for the domestic utility companies as of March 31, 2004:

	Authorized (in millions)
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)	-
Public Service Company of Oklahoma	300

(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.

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, and (iii) footnotes of each individual registrant. The Registrants' Combined Management's Discussion and Analysis section of the 2003 Annual Report should be read in conjunction with this report.

Significant Factors

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. In addition, legislation in some of our states requires RTO participation.

The status of the transfer of functional control of our subsidiaries' transmission systems to RTOs or the status of our participation in RTOs has not changed significantly from our disclosure as described in "RTO Formation" within the "Registrants' Combined Management's Discussion and Analysis" section of the 2003 Annual Report.

In November 2003, the FERC preliminarily found that certain AEP subsidiaries must fulfill their CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. FERC based their order on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. An ALJ held hearings on issues including whether the laws, rules, or regulations of Virginia and Kentucky prevent AEP subsidiaries from joining an RTO and whether the exceptions under PURPA 205(a) apply. The FERC ALJ affirmed the FERC's preliminary findings in March 2004. The FERC has not issued a final order in this matter.

In April 2004, KPCo reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC is expected to consider the settlement agreement in May 2004.

Litigation

AEP subsidiaries continue to be involved in various litigation matters as described in the "Significant Factors - Litigation" section of Registrants' Combined Management's Discussion and Analysis in the 2003 Annual Report. The 2003 Annual Report should be read in conjunction with this report in order to understand other litigation matters that did not have significant changes in status since the issuance of the 2003 Annual Report, but may have a material impact on future results of operations, cash flows and financial condition. Other matters described in the 2003 Annual Report that did not have significant changes during the first quarter of 2004, that should be read in order to gain a full understanding of the current litigation include disclosure related to the Texas Commercial Energy, LLP Lawsuit.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

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

Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted 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.

Enron bankruptcy summary - The amounts expensed in prior years in connection with the Enron bankruptcy 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 outcome of this lawsuit or its 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.

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 whether these governmental agencies will take further action with respect to these matters.

Environmental Matters

As discussed in the 2003 Annual Report, 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:

o Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
o New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
o Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

This discussion updates certain events occurring in 2004 and adds estimates of future capital expenditures for the Clean Water Act rule. You should also read the "Significant Factors - Environmental Matters" section within Registrants' Combined Management's Discussion and Analysis in the 2003 Annual Report for a complete description of all material environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) superfund and state remediation,
(4) global climate change, and (5) costs for spent nuclear fuel and decommissioning.

Future Reduction Requirements for SO2, NOx, 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 finalized designations for ozone non-attainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in state implementation plans (SIPs) to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of non-attainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA identified SO_2 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 SO_2 from the AEP System's generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

o The Federal EPA proposed an interstate air quality rule for reducing SO_2 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.
o 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 SO_2 emissions from coal-fired electric utility units. SO_2 and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 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 SO_2 and NO_x trading programs have not yet been proposed.

On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include "Best Available Retrofit" requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative "Best Available Retrofit" program based on emissions budgeting and trading programs. For utility units that are affected by the January 24, 2004 Interstate Air Quality Rule (IAQR), described above, the Federal EPA proposed that participation in the trading program under the IAQR would satisfy any applicable "Best Available Retrofit" requirements.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of maximum achievable control technology (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 SO_2 (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 SO_2 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, which can be used to comply with the more stringent SO_2 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. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register on March 16, 2004. Comments on both the initial proposal and the supplemental notice are due on or before June 29, 2004.

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 SO_2, 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.

New Source Review Litigation

Under the Clean Air Act (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 new source review requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications 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.

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, once-through cooled 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. All plants must reduce fish mortality by 80% to 95%. 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. These plants must reduce the rate of smaller organisms passing through the plant by 60% to 90%. 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. The capital cost of compliance for the AEP System's facilities, based on the Federal EPA's estimates in the rule, is $193 million. Any capital costs associated with compliance activities to meet the new performance standards would likely be incurred during the years 2008 through 2010. Management has not independently confirmed the accuracy of the Federal EPA's estimate. The rule has provisions to limit compliance costs. Management may propose less costly site-specific performance criteria if compliance cost estimates are significantly greater than the Federal EPA's estimates or greater than the environmental benefits. The rule also allows for mitigation (also called restoration measures) if it is less costly and has equivalent or superior environmental benefits than meeting the criteria in whole or in part. The following table shows the investment amount per subsidiary.

	Estimated Compliance Investments
	(in millions)
APCo	$21
CSPCo	19
I&M	118
OPCo	31

Other Matters

As discussed in the 2003 Annual Report, there are several "Other Matters" affecting AEP subsidiaries, including FERC's proposed standard market design and FERC's market power mitigation efforts. These were no significant changes to the status of FERC's proposed standard market design. The current status of FERC's market power mitigation efforts is described below.

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. In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. AEP and two unaffiliated utilities were required to submit generation market power analyses within sixty days of the FERC's order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. Management is unable to predict the outcome of these actions by the FERC or their affect on future results of operations and cash flows.

CONTROLS AND PROCEDURES

During the first quarter of 2004, 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 March 31, 2004, these officers concluded that the disclosure controls and procedures in place provide reasonable assurance that the disclosure controls and procedures accomplished 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 been no 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 first quarter of 2004 that have materially affected, or are reasonably likely to materially affect, AEP's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 5, Commitments and Contingencies, incorporated herein by reference.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended March 31, 2004 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number Of Shares Purchased (1)	Average Price Paid per Share	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans Or Programs
01/01/04 - 01/31/04	9	$65.00	-	$-
02/01/04 - 02/29/04	-	-	-	-
03/01/04 - 03/31/04	50	66.00	-	-
Total	59	$65.85	-	$-

(1) OPCo and PSO repurchased an aggregate of 9 shares of its 4.5% cumulative preferred stock and 50 shares of its 5% cumulative preferred stock, respectively, in privately-negotiated transactions outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Exhibit 12 - Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Exhibit 31.1 - Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2 - Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1 - Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

Exhibit 32.2 - Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

(b) Reports on Form 8-K:

The following reports on Form 8-K were filed during the quarter ended March 31, 2004.

Company Reporting	Date of Report	Item Reported
AEP	February 3, 2004	Item 7. Financial Statements and Exhibits
		Item 12. Results of Operations and Financial Condition
AEP	February 24, 2004	Item 7. Financial Statements and Exhibits
		Item 9. Regulation FD Disclosure

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto

Joseph M. Buonaiuto
Controller and
Chief Accounting
Officer

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

By: /s/Joseph M. Buonaiuto

Joseph M. Buonaiuto
Controller and
Chief Accounting
Officer

Date: May 7, 2004

"

EXHIBIT 12 "

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

	Year Ended December 31,					Twelve Months Ended
	1999	2000	2001	2002	2003	3/31/04
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	26,605
Interest on Short-term Debt	2,552	3,295	2,329	1,751	1,104	919
Miscellaneous Interest Charges	869	2,523	1,059	1,084	1,772	1,823
Estimated Interest Element in Lease Rentals	1,200	1,700	1,200	1,000	600	600
Total Fixed Charges	$30,858	$33,388	$29,066	$29,470	$29,943	$29,947
Earnings:						
Net Income Before Cumulative Effect of Accounting Change	$25,430	$20,763	$21,565	$20,567	$33,464	$33,933
Plus Federal Income Taxes	12,993	17,884	9,553	9,235	9,764	9,256
Plus State Income Taxes	2,784	2,457	489	1,627	(89)	371
Plus Fixed Charges (as above)	30,858	33,388	29,066	29,470	29,943	29,947
Total Earnings	$72,065	$74,492	$60,673	$60,899	$73,082	$73,507
Ratio of Earnings to Fixed Charges	2.33	2.23	2.08	2.06	2.44	2.45

"

EXHIBIT 31.1
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:
1. I have reviewed this report on Form 10-Q 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 officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) for the registrant and have:

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;

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 evaluation; and

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 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 officer(s) 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):

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

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: May 7, 2004

By: /s/ Michael G. Morris

Michael G. Morris
Chief Executive Officer

"

EXHIBIT 31.2
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:
1. I have reviewed this report on Form 10-Q 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 officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) for the registrant and 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 evaluation; 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 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 officer(s) 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: May 7, 2004

By: /s/ Susan Tomasky

Susan Tomasky
Chief Financial Officer

"

Exhibit 32.1

This Certification 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 Quarterly Report of the Companies (as defined below) on Form 10-Q for the quarterly period endedMarch 31, 2004as filed with the Securities and Exchange Commission on the date hereof (the "Reports"), 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
May 7, 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.

"

Exhibit 32.2

This Certification 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 Quarterly Report of the Companies (as defined below) on Form 10-Q for the quarterly period endedMarch 31, 2004as filed with the Securities and Exchange Commission on the date hereof (the "Reports"), 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
May 7, 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.

End of Filing