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 JUNE 30, 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 at July 30, 2004	Par Value at July 30, 2004
American Electric Power Company, Inc.	395,658,435	$6.50
AEP Generating Company	1,000	1,000
AEP Texas Central Company	2,211,678	25
AEP Texas North Company	5,488,560	25
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
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June 30, 2004

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SIGNATURE

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 AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
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 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central Company, an AEP electric utility subsidiary.
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.
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, including storms.
o Available sources and costs of, and transportation for, 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, litigation 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 new investments and 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 constrain 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.

EXECUTIVE OVERVIEW

Divestiture Plans

As outlined in our 2003 Annual Report, we are continuing with our strategy of disposing of various unregulated non-core businesses and assets in order to focus management efforts on our core assets and operations and to eliminate the negative earnings and cash consequences of these non-regulated operations. We are also continuing the process of disposing of the generating assets of AEP Texas Central Company (TCC) which will allow us to determine stranded costs for recovery under Texas regulation.

During the first half of 2004, we (a) completed the sale of our interest in the Pushan Power Plant, (b) closed on the sale of Louisiana Intrastate Gas Pipeline Company and its approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana and five gas processing facilities that straddle the system, and (c) completed the sale of assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal. These sales did not have a significant effect on our results of operations for the second quarter 2004 or for the six months ended June 30, 2004.

In July 2004, we completed the sale of two coal-fired power plants in the U.K. (Fiddler's Ferry in northwest England and Ferrybridge in northeast England), related coal assets and a number of related commodities contracts. This sale includes substantially all of our operations and assets in the Investments - UK Operations segment. In July 2004, we also completed the sale of certain generation assets within TCC, including eight natural gas plants, one coal-fired plant and one hydro plant. We also closed on the sale of our ownership interests in our two independent power producers in Florida and one in Colorado. We anticipate the sale of our remaining independent power producer in Colorado will be closed as soon as necessary regulatory approvals are obtained.

We are also making progress on the sale of our remaining TCC and non-core assets. For TCC's assets, we have agreements for the sale of TCC's share of the Oklaunion Power Station and TCC's share of the South Texas Project nuclear plant. The co-owners of these facilities have notified TCC of their intentions to exercise rights of first refusal, but we still expect to sell these assets by the end of 2004. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances which may delay the closings. We also anticipate being able to reach an agreement for the sale of Jefferson Island Storage and Hub, L.L.C., which holds the remaining LIG Pipeline Company gas storage assets, by the end of the year.

We will continue to review our portfolio of businesses and assets for additional divestiture opportunities which will further our goal of divesting of assets and investments that are not a core part of our U.S. utility operations or are not activities that will support or complement our regulatory utility business.

As indicated in our 2003 Annual Report, we are utilizing and will continue to utilize the cash generated by the sale of certain assets to reduce existing long-term debt and other obligations. During the six months ended June 30, 2004, we reduced long-term debt by approximately $703 million. In July 2004, we retired in excess of $500 million of additional long-term debt that we currently do not plan to refinance, using cash on hand, proceeds from the issuance of commercial paper and the net cash proceeds from the sale of certain Texas generation assets. We anticipate further reductions of long-term debt over the remainder of 2004. The result of our use of cash on hand and sales proceeds to reduce debt has decreased our percentage of debt to total capitalization ratio from 64.6% at December 31, 2003 to 63.3% at June 30, 2004.

Utility Operations

We continue to generate expected results from our Utility Operations as our net income from Utility Operations was $183 million for the second quarter 2004 and $486 million for the six-months ended June 30, 2004, although, these results are not as strong when compared to the same periods in the prior year. Gross margins improved in both periods driven by healthy utility sales increases in all regions except Texas and improvements in the economy, but were more than offset by increased expenses from outage maintenance and distribution system reliability improvement work.

We made progress concerning regulatory challenges related to integration of the AEP East companies into PJM (scheduled for October 1, 2004). A settlement agreement was approved by the KPSC. A settlement was also reached with interested parties in Virginia and is pending before the Virginia SCC for approval. These settlements should allow the integration to proceed on time.

We announced during 2004 that we intend to invest approximately $3.5 billion on environmental upgrades from 2004 to 2010 at our coal-fired generation plants in order to continue our goal of producing low-cost electricity with minimal impact on the environment. We continue to believe that investing in environmental upgrades at existing plants is in the best interest of both our customers and our business. Our commitment to make these investments is conditioned on receiving appropriate recovery for our costs.

Texas Regulatory Activity

The issue of stranded cost recovery in Texas continues to be a major focus for us. At June 30, 2004, we have recorded net regulatory assets of approximately $1.4 billion in stranded costs and other amounts that TCC will seek recovery of in the true-up proceeding before the PUCT. We currently expect our stranded cost filing to request recovery of amounts in excess of our related regulatory assets. Although we believe that the regulatory assets that we have recorded are appropriate, the ultimate outcome of the true-up proceeding before the PUCT could have a negative effect on our future results of operations, cash flows and financial condition.

Common Stock Dividends

After the completion of our planned divestitures and after the results of our Ohio and Texas rate proceedings are known, we hope to be able to recommend to the Board of Directors a moderate increase in our common stock dividend from its current level of 35 cents per share per quarter.

Reorganization

In addition to the significant changes occurring as a result of our divestiture plan, we also recently reorganized and put in place a new management team that will place increased emphasis on our energy delivery and distribution activities through our existing operating companies which have been organized into seven regions. As a consequence, we appointed seven regional presidents and their respective teams. They are in place and operating as of the end of July. These seven new regional presidents and their management teams will focus on responding more quickly to the needs of our customers in their regions. This change supports our long-term focus of creating stronger utility businesses, more in touch with the local needs of customers and regulators.

For additional information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations," including "Business Strategy," in our 2003 Annual Report. Also see the remainder of our "Management's Financial Discussion and Analysis of Results of Operations" in this Form 10-Q, along with the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

Segments

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's U.K. plants

o Investments-Other:
o Bulk commodity barging operations, windfarms, independent power producers 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.

There are numerous changes occurring in the businesses included in our segments as a result of our continued divestiture of certain non-core operations. Substantially all operations and assets within our Investments - UK Operations segment were sold in July 2004. Within our Investments - Gas Operations segment, we have recently sold LIG Pipeline Company, which included the gas pipeline portion of Louisiana Intrastate Gas, and are currently marketing Jefferson Island Storage & Hub, L.L.C., which holds the remaining Louisiana gas storage assets held for sale. Upon completion of the divestiture of our non-core assets, the only substantive portion of the Investments - Gas Operations business that will remain is our Houston Pipe Line Company L.P. (HPL) operations, which include the Bammel storage facility, and we will continue to operate HPL as we evaluate our future plans for this investment.

In addition, there have been numerous divestitures of businesses, assets and investments within our Investments - Other segment over the course of this past year including AEP Coal and our interest in the Pushan Power Plant. Our goal for the remaining assets in this segment, which includes our unregulated investments in wind farms, and barging and river transportation groups, is to operate them in such a way that they complement our core capabilities in regulated utility operations.

All of the changes in these segments are leading us to review our business model of the future and how we intend to manage our business overall. We intend to make decisions over the course of the remainder of the year which may lead to changes in our reported business segments.

AEP Consolidated Results

American Electric Power Company's consolidated Net Income for the three and six month periods ended June 30, 2004 and 2003 was as follows (Earnings and Average Shares Outstanding in millions):

	Second Quarter				Six Months Ended June 30,			
	2004		2003		2004		2003	
	Earnings	EPS	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$183	$0.46	$225	$0.57	$486	$1.23	$531	$1.41
Investments - Gas Operations	(4)	(0.01)	(25)	(0.06)	(13)	(0.03)	(43)	(0.11)
Investments - UK Operations	-	-	-	-	-	-	-	-
Investments - Other	(3)	(0.01)	(20)	(0.05)	1	-	-	-
All Other*	(25)	(0.06)	(3)	(0.01)	(34)	(0.09)	(18)	(0.05)
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	151	0.38	177	0.45	440	1.11	470	1.25
Investments - Gas Operations	2	-	1	-	1	-	4	0.01
Investments - UK Operations	(52)	(0.13)	4	0.01	(64)	(0.16)	(37)	(0.09)
Investments - Other	(1)	-	(7)	(0.02)	5	0.01	(15)	(0.04)
Discontinued Operations	(51)	(0.13)	(2)	(0.01)	(58)	(0.15)	(48)	(0.12)
Utility Operations	-	-	-	-	-	-	236	0.63
Investments - Gas Operations	-	-	-	-	-	-	(22)	(0.06)
Investments - UK Operations	-	-	-	-	-	-	(21)	(0.06)
Cumulative Effect of Accounting Changes	-	-	-	-	-	-	193	0.51
Total Net Income	$100	$0.25	$175	$0.44	$382	$0.96	$615	$1.64
Average Shares Outstanding		396		395		396		376

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

Second Quarter 2004 Compared to Second Quarter 2003

Income Before Discontinued Operations and Cumulative Effect of Accounting Changes decreased $26 million to $151 million in 2004 compared to 2003. Net Income for 2004 of $100 million or $0.25 per share includes a loss, net of taxes, from discontinued operations of $51 million. Net Income for 2003 of $175 million or $0.44 per share includes a loss, net of taxes, from discontinued operations of $2 million.

For the second quarter 2004 our Utility Operations Net Income decreased $42 million, or almost 19%, from the previous year driven by increased spending on operations and maintenance expenses. Our UK Operations (which were sold on July 30, 2004) also contributed $56 million to the decrease in net income in the second quarter 2004. Our Gas Operations and Other Investments segments posted better results in 2004. Our Gas Operations segment benefited from increased earnings from pipeline optimization and storage activities and lower operating expenses, and our Investments - Other segment benefited from a reduction in our provisions for uncollectible accounts receivable and lower overall expenses in 2004.

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 its coal procurement and transportation operations. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment. LIG's operations include 2,000 miles of intrastate gas pipelines, gas processing facilities and a 9.7 billion cubic feet natural gas storage facility. LIG Pipeline Company, which owned the pipeline and processing operations of LIG, was sold in April 2004 (see Note 7).

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Income Before Discontinued Operations and Cumulative Effect of Accounting Changes decreased $30 million to $440 million in 2004 compared to 2003. Net Income for 2004 of $382 million or $0.96 per share includes a loss, net of taxes, from discontinued operations of $58 million. Net Income for 2003 of $615 million or $1.64 per share includes a loss, net of taxes, from discontinued operations of $48 million and a benefit from a net $193 million of cumulative effect of changes in accounting related to asset retirement obligations and accounting for risk management contracts.

For the six months ended June 30, 2004, Utility Operations Income Before Discontinued Operations and Cumulative Effect of Accounting Changes decreased $45 million or almost 8.5% from the previous year driven by increased spending on operations and maintenance expenses. Our UK Operations (which were sold on July 30, 2004) also were responsible for $6 million (including cumulative effect of accounting changes) of the decrease in Net Income in 2004, while we sought a buyer for our U.K. assets, all of which are part of discontinued operations. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment. Our Investments-Gas Operations segment posted a lower loss in 2004, benefiting from improved margins and reductions in operating expenses.

Our results of operations by operating segment are discussed below.

Utility Operations

	Second Quarter 2004	Second Quarter 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(in millions)			
Revenues	$2,544	$2,665	$5,149	$5,371
Fuel and Purchased Power	821	956	1,581	1,846
Gross Margin	1,723	1,709	3,568	3,525
Depreciation and Amortization	308	315	618	610
Other Operating Expenses	998	889	1,911	1,760
Operating Income	417	505	1,039	1,155
Other Income (Expense), Net	16	5	25	3
Interest Expense and Preferred Stock Dividend Requirements	157	167	320	331
Income Tax Expense	93	118	258	296
Income Before Discontinued Operations and Cumulative Effect	$183	$225	$486	$531

Summary of Selected Sales Data
For Utility Operations

	Second Quarter 2004	Second Quarter 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Energy Summary	(in millions of KWH)			
Retail				
Residential	9,740	8,659	23,167	22,080
Commercial	9,390	8,773	18,169	17,568
Industrial	12,902	12,449	25,175	24,455
Miscellaneous	806	734	1,549	1,424
Subtotal	32,838	30,615	68,060	65,527
Texas Retail and Other	262	739	486	1,538
Total	33,100	31,354	68,546	67,065
Wholesale	19,884	16,357	39,225	36,716

Second Quarter Six Months Ended June 30,

Weather Summary	2004	2003	2004	2003
	(in degree days)			
Eastern Region				
Actual - Heating	167	141	2,031	2,169
Normal - Heating*	180	**	1,986	**
Actual - Cooling	313	157	316	158
Normal - Cooling*	278	**	281	**
Western Region (PSO/SWEPCo)				
Actual - Heating	30	34	913	1,074
Normal - Heating*	33	**	1,012	**
Actual - Cooling	659	638	689	644
Normal - Cooling*	642	**	660	**

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

Second Quarter 2004 Compared to Second Quarter 2003

Income from Utility Operations decreased $42 million to $183 million in 2004. The key driver of the decrease was a $109 million increase in other operating expenses, partially offset by a $14 million increase in gross margin, a $25 million decrease in income taxes, and a $28 million net decrease in other expenses.

The major components of our change in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

o Overall retail margins (excluding fuel recovery) in our utility business increased $47 million. Residential demand increased over the prior year as a consequence of higher usage by customers resulting from favorable weather. Cooling degree days were up significantly in the East and off slightly in the West. Heating degree days were up in the East and off slightly in the West as compared to the prior year. Commercial and industrial demand also increased resulting from the economic recovery in our regions.
o Fuel recovery in our non-Texas utility business was a net $37 million favorable in comparison to last year primarily due to higher fuel costs in the prior year resulting from the conclusion of the amortization of Cook plant outage costs and a fish intrusion outage causing us to purchase higher priced non-nuclear power in 2003.
o Our Texas supply business had a $31 million decrease in gross margin principally due to a $52 million decrease resulting from increased provisions for potential fuel disallowances in Texas, offset by a $21 million increase from a favorable adjustment recorded in 2004 to a retail clawback refund related to the number of customers receiving price-to-beat service in Texas.
o Beginning in 2004, the wholesale capacity auction true-up ceased per rules of the PUCT, therefore revenues are no longer recognized, resulting in $52 million of lower regulatory deferrals in 2004. For the years 2003 and 2002, we recognized the non-cash revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
o Margins from off-system sales for 2004 were $9 million better than 2003 due to favorable power and coal optimization activity, slightly offset by lower volumes.

Utility operating expenses and income tax expense changed between years as follows:

o Maintenance and Other Operation expense increased $89 million due to a $33 million increase from the timing of planned plant outages in 2004 as compared to 2003, $29 million of increased distribution maintenance expense primarily from storm damage and system reliability work, and a $14 million net increase in employee-related benefits and insurance, magnified by favorable adjustments in 2003. These increases were offset, in part, by $10 million due to the conclusion of the amortization of our deferred Cook nuclear plant restart settlement expenses. Expenses of $23 million, comprised of several miscellaneous items, make up the remainder of the increase.

o Income Tax Expense decreased $25 million almost entirely due to the decrease in pre-tax income.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Income from Utility Operations, before $236 million of cumulative effect of accounting changes in 2003, decreased $45 million to $486 million in 2004. Key drivers of the change include a $151 million increase in Other Operating Expenses, offset by a $43 million increase in gross margin, a $38 million decrease in income taxes, a $22 million increase in net other income and a $3 million net decrease in other expense line items.

The major components of our change in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

o Overall retail margins (excluding fuel recovery) in our utility business increased $63 million. Residential demand in the East increased over the prior year as a consequence of higher usage by customers partially resulting from favorable weather while demand in the West was off slightly. Cooling degree days were up significantly in the East and up slightly in the West. Heating degree days were off slightly in the East and off in the West as compared to the prior year. Overall commercial and industrial demand also increased resulting from the economic recovery in our regions.
o Fuel recovery in our non-Texas utility business was a net $59 million favorable in comparison to last year primarily due to higher fuel costs in the prior year resulting from the conclusion of the amortization of deferred Cook plant outage costs and a fish intrusion outage causing us to purchase higher priced non-nuclear replacement power in 2003.
o Our Texas supply business had a $43 million decrease in gross margin principally due to a $27 million decrease resulting from increased provisions for potential fuel disallowances in Texas, a $31 million impact from lower Reliability-Must-Run (RMR) contract margins, and a $16 million unfavorable variance due to declining commercial and industrial business in Texas, offset by a $21 million increase from a favorable adjustment recorded in 2004 to a retail clawback refund related to the number of customers receiving price-to-beat service in Texas.
o Beginning in 2004, the wholesale capacity auction true-up ceased per rules of the PUCT, therefore revenues are no longer recognized, resulting in $108 million of lower regulatory deferrals in 2004. For the years 2003 and 2002, we recognized the non-cash revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCT's excess cost over market model.
o Margins from off-system sales for 2004 were $60 million better than in 2003 due to favorable power and coal optimization activity, slightly offset by lower volumes.

Utility operating expenses and income tax expense changed between years as follows:

o Maintenance and Other Operation expense increased $135 million due to a $63 million increase from the timing of planned plant outages in 2004 as compared to 2003, $28 million of increased distribution maintenance expense from system reliability work and a $30 million net increase in employee-related benefits, insurance and other administrative expenses magnified by favorable adjustments in 2003. These increases were offset, in part, by $20 million due to the conclusion of the amortization of our deferred Cook nuclear plant restart settlement expenses. Expenses of $34 million, comprised of several miscellaneous items, make up the remainder of the increase.
o The remaining $16 million of the increase in Other Operating Expenses was a result of an increase in taxes other than income taxes.
o Income Tax Expense decreased $38 million due to the decrease in pre-tax income and other tax return adjustments.

Investments - Gas Operations

	Second Quarter		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in millions)			
Revenue	$817	$675	$1,468	$1,623
Purchased Gas	773	684	1,385	1,574
Gross Margin	44	(9)	83	49
Maintenance and Other Operation	31	36	60	74
Other Operating Expense	3	6	6	11
Operating Income (Loss)	10	(51)	17	(36)
Other Income (Expense), Net	(3)	1	(9)	(5)
Interest Expense	13	14	25	26
Income Tax Benefit	2	39	4	24
Net Loss Before Discontinued Operations and Cumulative Effect	$(4)	$(25)	$(13)	$(43)

Second Quarter 2004 Compared to Second Quarter 2003

Our $4 million loss from Gas Operations before discontinued operations and cumulative effect of accounting changes compares with a $25 million loss recorded in the second quarter of 2003. Gross margins improved $53 million year-over-year driven by improvements in our earnings from pipeline optimization and storage activities. Operating expenses decreased by $8 million as a result of reduced gas trading activities and lower depreciation resulting from 2003 asset impairments. Income tax benefits decreased by $37 million due to the improvement in pre-tax income and a $16 million tax benefit adjustment from a capital loss recorded in the second quarter of 2003.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Our $13 million loss from Gas Operations before discontinued operations and cumulative effect of accounting changes compares with a $43 million loss recorded in the year-to-date June 2003 period. Gross margins improved $34 million year-to-date June 30, 2004 to $83 million. The increase in margins were driven by $20 million of significant losses in 2003 from servicing a single contract when gas prices were at an all time high, and $6 million higher pipeline and pipeline optimization margins in 2004. In addition, operating expenses decreased $19 million between periods due to reduced gas trading activities and lower depreciation resulting from 2003 asset impairments. Income tax benefits decreased by $20 million primarily due to the improvement in pre-tax income.

Investments - UK Operations

Second Quarter 2004 Compared to Second Quarter 2003

Our UK Operations (all classified as Discontinued Operations) incurred a loss of $52 million for 2004 compared with income of $4 million in 2003. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment.

Our UK Operations' gross margins from generation increased $11 million in 2004, reflecting the improvement in wholesale electricity prices in the U.K. These improvements were offset by a $32 million decrease in margins from risk management activity primarily resulting from AEP's decision to exit trading in the first quarter of 2004 and the closure and settlement of non-core and residual positions, as well as an increase of $37 million in maintenance and other operation expense due to several factors, including the expensing of capital expenditures during held-for-sale status to maintain the appropriate fair value of the fixed assets and higher connection charges resulting from a re-zoning of the plants.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Our UK Operations (all classified as Discontinued Operations) incurred a loss of $64 million for 2004 compared with a loss of $37 million in 2003, before the cumulative effect of accounting change. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment.

Our UK Operations' gross margins from generation increased $40 million as a result of a 4% increase in generation and favorable price variances. Risk management margin was lower by $63 million resulting from AEP exiting trading in the first quarter of 2004 and the closure and settlement of non-core and residual positions. Operating expenses were unfavorable by $33 million due to several factors, including the expensing of capital expenditures during the held-for-sale status to maintain the appropriate fair value of the fixed assets and higher connection charges resulting from a re-zoning of the plants. Depreciation and amortization decreased $10 million due to the cessation of plant depreciation due to the held-for-sale status of assets.

Investments - Other

Second Quarter 2004 Compared to Second Quarter 2003

Loss before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment decreased by $17 million to $3 million in 2004.

The decrease in the loss is due to the following:

(a) Our AEP Texas Provider of Last Resort (POLR) entity recorded a $6 million provision for uncollectible receivables in the second

quarter 2003 that did not reoccur in 2004,
(b) Our AEP Resources entity decreased its loss by $7 million in the second quarter 2004 as compared to 2003 primarily due to lower interest expense resulting from equity capital infusions in mid and late 2003 that were used to reduce debt and other corporate borrowings, and
(c) Our AEP Pro Serv entity reduced losses from $4 million to break even, primarily due to operations winding down in 2004.

In addition to the items above, the results from our IPPs and windfarms decreased $3 million primarily driven by an additional $1.6 million impairment recorded by one of our Colorado IPPs in June 2004 and an additional $1 million of expense related to unfavorable unit outages at our Mulberry unit in Florida and maintenance at our Sweeney unit in Texas. These decreases of $3 million were equally offset by other insignificant increases at other investment entities.

In discontinued operations, Eastex was sold in the third quarter 2003 and Pushan Power Plant was sold in March 2004.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Income before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment increased from no income to $1 million of income in 2004.

The key components of the increase in income were as follows:

(a) Our AEP Texas Provider of Last Resort (POLR) entity recorded a $6 million provision for uncollectible receivables in the first six months of 2003 that did not reoccur in 2004,
(b) Our AEP Resources entity decreased their loss by $17 million for the first six months of 2004 versus 2003, primarily due to lower interest expense resulting from equity capital infusions in mid and late 2003 that were used to reduce debt and other corporate borrowings,
(c) Our AEP Pro Serv entity reduced losses from $4 million to break even, primarily due to operations winding down in 2004, and
(d) Our other entities had individually insignificant changes in results totaling a net $5 million increase in income between years.

Offsetting these increases was a $31 million nonrecurring gain recorded in the first quarter of 2003 primarily related to a gain from the sale of Mutual Energy.

In discontinued operations, Eastex was sold in the third quarter 2003 and Pushan Power Plant was sold in March 2004.

All Other

Second Quarter 2004 Compared to Second Quarter 2003

Our parent company's second quarter 2004 expenses increased $22 million over the second quarter 2003 resulting primarily from a $6 million decrease in interest income generated from a lower average intercompany debt receivable balance and lower net invested cash during the quarter, a $7 million increase in interest expense resulting primarily from accelerated discount amortization from the early redemption of senior notes in May 2004, a $2 million decrease in parent guarantee fee income, and an additional net $7 million increase in other expenses, none individually significant.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Our parent company's year-to-date 2004 expenses increased $16 million over the year-to-date 2003 time period primarily due to a $17 million decrease in interest income generated from a lower average intercompany debt receivable balance and lower net invested cash during the six months in 2004, a $3 million decrease in parent guarantee fee income, and a $2 million increase in other expenses, partially offset by a $6 million decrease in operations and maintenance expense resulting from lower general advertisement expenses in 2004.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 34.1% and 24.7%, respectively. The increase in the effective tax rate is primarily due to realizing a tax benefit from a capital loss in the second quarter of 2003. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes.

The effective tax rates for the first six months of 2004 and 2003 were 35.3% and 35.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes. The effective tax rates remained flat for the comparative period.

FINANCIAL CONDITION

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

Capitalization

	June 30, 2004	December 31, 2003
Common Equity	36.4%	35.1%
Preferred Stock	0.3	0.3
Preferred Stock (Subject to Mandatory Redemption)	0.3	0.3
Long-term Debt, including amounts due within one year	60.3	62.8
Short-term Debt	2.7	1.5
Total Capitalization	100.0%	100.0%

Our $1.3 billion in cash flows from operations, combined with our reduction in cash expenditures for investments in discontinued operations, a second quarter of 2003 reduction in dividends paid and the use of a portion of our cash on hand, allowed us to reduce long-term debt by $703 million, while only increasing short-term debt by $270 million. Our common equity percentage benefited from the issuance of $11 million of new common equity (related to our incentive compensation plans) and the fact that our earnings exceeded our dividends for the six months ended June 30, 2004. As a consequence of the capital changes during the six months, we improved our ratio of debt to total capital from 64.6% to 63.3% (preferred stock subject to mandatory redemption is included in debt component of ratio).

In July 2004, we retired in excess of $500 million of long-term debt that we currently do not plan to refinance, using cash on hand, proceeds from the issuance of commercial paper and a portion of the net cash proceeds from the sale of certain Texas generation assets.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. 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 June 30, 2004, of approximately $3.4 billion as illustrated in the table below.

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit	$1,000	May 2005
Lines of Credit	750	May 2006
Lines of Credit	1,000	May 2007
Euro Revolving Credit Facility	184	October 2004
Letter of Credit Facility	200	September 2006

Total	3,134
Cash and Cash Equivalents	858
Total Liquidity Sources	3,992
Less: AEP Commercial Paper Outstanding	554(a)
Letters of Credit Outstanding	52
Net Available Liquidity at June 30, 2004	$3,386

(a) Amount does not include JMG Funding LP commercial paper outstanding in the amount of $21 million. This commercial paper is specifically associated with the Gavin scrubber lease and does not reduce available liquidity to AEP.

Debt Covenants and Borrowing Limitations

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 June 30, 2004, we were in compliance with the covenants contained in these credit agreements and debt to total capitalization was 58.0%. Non-performance of these covenants could result in an event of default under 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 revolving credit 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, we 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. At June 30, 2004, we were in compliance with this order.

Money pool and external borrowings may not exceed SEC or state commission authorized limits. At June 30, 2004, we had not exceeded the SEC or state commission authorized limits.

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 and the use of cash on hand. Our ratings have not been adjusted by any rating agency during 2004. On August 2, 2004, Moody's Investors Service (Moody's) changed their ratings outlook on AEP to "positive" from "stable," while keeping the remaining rated subsidiaries on "stable" outlook. The other major rating agencies currently have AEP and our rated subsidiaries on "stable" outlook. Our current ratings by the major agencies 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

If we receive a downgrade in our credit ratings by one of the nationally recognized rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Common Stock Dividends

After the completion of our planned divestitures and after the results of our Ohio and Texas rate proceedings are known, we hope to be able to recommend to the Board of Directors a moderate increase in our common stock dividend from its current level of 35 cents per share per quarter.

Cash Flow

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

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$976	$1,088
Net Cash Flows From Operating Activities	1,262	850
Net Cash Flows Used For Investing Activities	(575)	(1,288)
Net Cash Flows From (Used For) Financing Activities	(805)	420
Net Decrease in Cash and Cash Equivalents	(118)	(18)
Cash and Cash Equivalents at End of Period	$858	$1,070

In addition to cash on hand, 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 our other subsidiaries that are not participants in the non-utility money pool. As of June 30, 2004, we had credit facilities totaling $2.75 billion to support our commercial paper program. At June 30, 2004, AEP had $596 million outstanding in short-term borrowings of which $554 million was commercial paper supported by the revolving credit facilities. In addition, JMG had commercial paper outstanding in the amount of $21 million. This commercial paper is specifically associated with the Gavin scrubber lease and is not supported by our credit facilities. The maximum amount of AEP commercial paper outstanding during the quarter ended June 30, 2004 was $661 million. The weighted-average interest rate for our commercial paper during the second quarter 2004 was 1.42%.

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.

Operating Activities

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Net Income	$382	$615

Plus: Losses from Discontinued Operations	58	48
Income from Continuing Operations	440	663
Noncash Items Included in Earnings	766	462
Changes in Assets and Liabilities	56	(275)
Net Cash Flows From Operating Activities	$1,262	$850

2004 Operating Cash Flow

Our cash flows from operating activities were $1,262 million for the first six months of 2004. We produced income from continuing operations of $440 million during the period. Income from continuing operations for the period included noncash expense items of $716 million for depreciation, amortization and deferred taxes. In addition, there is a current period impact for a net $50 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 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 an increase in the balance of fuel, materials and supplies of $196 million, and an increase in the balance of accrued taxes of $140 million.

2003 Operating Cash Flow

Our cash flows from operating activities were $850 million for the first six months of 2003. We produced income from continuing operations of $663 million during the period. Income from continuing operations for the period included noncash items of $668 million for depreciation, amortization, and deferred taxes, and $193 million related to the cumulative effect of accounting changes. There was a current period impact for a net $33 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 $108 million, increases in customer deposits and risk management collateral of $167 million, increases in accrued taxes of $62 million and changes in accounts receivable and accounts payable of $145 million.

Investing Activities

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Construction Expenditures	$(697)	$(639)
Change in Other Cash Deposits, Net	(2)	23
Investment in Discontinued Operations, net	-	(716)
Proceeds from Sale of Assets	131	41
Other	(7)	3
Net Cash Flows Used for Investing Activities	$(575)	$(1,288)

Our cash flows used for investing activities decreased $713 million from the same period in the prior year primarily due to investments made in our U.K. operations during 2003 that did not recur during 2004.

Financing Activities

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Issuances of Common Stock	$11	$1,142
Issuances/Retirements of Debt, net	(535)	(153)
Retirement of Preferred Stock	(4)	(2)
Retirement of Minority Interest	-	(225)
Dividends	(277)	(342)
Net Cash Flows From (Used for) Financing Activities	$(805)	$420

Our cash flow from financing activities in 2004 decreased $1.2 billion from the $420 million net cash inflow recorded in 2003. During the first quarter of 2003, we issued common stock for $1,142 million and subsequent to the first quarter of 2003, we reduced our dividend. This compares to only $11 million of cash proceeds from the issuance of common stock under our incentive compensation plans in the first six months of 2004.

During the first six months of 2004, we used approximately $986 million of cash to retire long-term debt. We also issued approximately $268 million of long-term debt ($263 million net of issuance costs) including $173 million of pollution control bonds (installment purchase contracts). These activities were supported by the generation of $1.3 billion in cash flow from operations. See Note 10 "Financing Activities" for further information regarding issuances and retirements of debt instruments during the first six months of 2004.

Off-balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. 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 policy restricts 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) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease for up to 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on 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.

At June 30, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and we estimate total costs for the completed Facility to be approximately $525 million, funded through long-term debt financing of $494 million and equity of $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. For the initial 5-year lease term, the base lease rental is equal to the interest on Juniper's debt financing at a variable rate indexed to three-month LIBOR (1.61% as of June 30, 2004) plus 100 basis points, plus a fixed return on Juniper's equity investment in the Facility and certain other fixed amounts. Consequently, as LIBOR increases, the base rental payments under the Juniper Lease will also increase.

The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's obligations as a liability of $520 million. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based upon the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

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 (Tractebel SA) 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. Management believes the PPA is enforceable. The litigation is now in the discovery phase.

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). In addition to the following discussion, see Note 7 of our Notes to Consolidated Financial Statements within this Form 10-Q.

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
7.81% 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) closing on the sale of TCC's remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro plant for approximately $425 million, net of adjustments. Subject to certain issues that have arisen relating to co-owners' rights of first refusal, we expect the sales of TCC's shares of Oklaunion and South Texas Project to close before the end of 2004. There could, however, be potential delays in receiving necessary regulatory approvals and clearances which may delay the closing. The sale of TCC's remaining generation assets was completed in July 2004. We will file with the PUCT to recover net stranded costs associated with each of the sales pursuant to Texas restructuring legislation.

AEP Coal

As a result of management's decision to exit our non-core businesses, we retained an advisor in 2003 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 2004 results of operations was not 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 or selling our interest in Houston Pipe Line Company L.P., including the Bammel storage facility, which is part of our Investments-Gas Operations segment. In February 2004, we signed an agreement to sell LIG Pipeline Company, which contained the pipeline and processing assets of Louisiana Intrastate Gas (LIG). The sale was completed in early April 2004 and the impact on results of operations in the second quarter of 2004 was not significant. We continue to market Jefferson Island Storage & Hub, L.L.C., the remaining LIG gas storage entity, and anticipate the sale before the end of 2004.

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 domestic IPP investments for a sales price of $156 million, subject to closing adjustments. An additional pre-tax impairment of $1.6 million was recorded in June 2004 (recorded in Maintenance and Other Operation expense) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004, resulting in a pre-tax gain of approximately $100 million, generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded during July 2004. The sale of the Ft. Lupton, Colorado plant is awaiting FERC approval and is expected to close during the third quarter 2004, with no significant effect on results of operations during the third quarter 2004.

UK Operations

In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment for approximately $456 million. The sale included Fiddler's Ferry, a coal-fired power plant in northwest England, Ferrybridge, a coal-fired power plant in northeast England, related coal assets, and a number of related commodities contracts. We are still determining the final impact from the sale on our third quarter 2004 results of operations. Although the final sales price will be subject to closing adjustments, expected to be determined during the third quarter 2004, we believe that a gain on sale, which would be included in discontinued operations, may result.

Other

We continue to have discussions with various parties on business alternatives for certain of our other non-core investments, which may result in further dispositions in the future.

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 or gains upon the eventual 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 issued a final order in June 2004.

In April 2004, we reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC approved the settlement agreement in May 2004 and the FERC approved the settlement in June 2004.

In July 2004, we reached an agreement with the intervenors to settle the RTO issues in Virginia. The settlement agreement is now subject to approval by the Virginia SCC.

If the Virginia settlement is approved, it should allow our AEP East companies to join PJM and address state concerns without any significant expected adverse impacts on future results of operations.

AEP West companies are members of ERCOT or SPP. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

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 six months 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) Potential Uninsured Losses.

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

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 (the 10.5 BCF and 55 BCF described in the preceding 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. Also 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 the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value.

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, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements.

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. The parties are currently in non-binding court-sponsored mediation.

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. The parties are currently in non-binding court-sponsored mediation.

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 these lawsuits or their impact on our results of operations, cash flows or financial condition.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas Retail Electric Provider (REP), filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

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. 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 responded to that request. The case is in the initial pleading stage with our response to the complaint currently due on September 13, 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 future results of operations, financial condition or cash flows. Management cannot predict whether these governmental agencies will take further action with respect to these matters.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input valve, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input valve in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, and the referenced recordkeeping and reporting requirements and heat input valve at Welsh. We are preparing additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, cash flows or financial condition.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other unaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of two special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. Management believes the actions are without merit and intends to vigorously defend against the claims.

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 emerging environmental control requirements that we expect 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 (SO2), nitrogen oxide (NOx) 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. 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 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 disposal 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 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 a Clean Air Interstate Rule (CAIR) to reduce SO2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the new 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 CAIR 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 were proposed on June 10, 2004.

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 CAIR, described above, the Federal EPA proposed that participation in the trading program under the CAIR would satisfy any applicable "Best Available Retrofit" requirements. However, the guidance preserves the ability of a state to require site-specific installation of pollution control equipment through the SIP for purposes of abating regional haze.

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. The proposed standards for sub-bituminous coals 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 CAIR. 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 effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 tons to 34 tons by 2010 and to 15 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. We filed comments on both the initial proposal and the supplemental notice in June 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.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA is expected to file a motion to amend its complaint, and, to the extent that motion seeks to expand the scope of the pending litigation, the AEP subsidiaries will oppose that motion.

We are unable to estimate the loss or range of loss related to any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, 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 other pending CAA litigation against unaffiliated utility companies referenced in the annual report, the petition for certiorari filed with the Supreme Court in the TVA litigation was denied by the Court on May 3, 2004. In addition, the United States has filed a notice of appeal with the Fourth Circuit Court of Appeals from the adverse decision in the Duke case, and a briefing order has been issued by the Court that will require briefing to be completed by late September 2004.

Clean Water Act Regulation

On July 9, 2004, the Federal EPA published in the Federal Register 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 estimated capital cost of compliance for our facilities, based on the Federal EPA's analysis 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. Several states, electric utilities (including our APCo subsidiary) and environmental groups appealed certain aspects of the rule. We cannot predict the outcome of the appeals.

Spent Nuclear Fuel Disposal

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STP Nuclear Operating Company on behalf of TCC and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continued on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase. If such cost increases are not recovered on a timely basis in regulated rates, future results of operations and cash flows could be adversely affected.

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Critical Accounting Estimates

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. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. 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. We plan to present evidence to demonstrate that we do not possess market power in geographic areas where we sell wholesale power.

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 that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, Credit Risk Management, 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)
Six Months Ended June 30, 2004

	Utility Operations	Investments Gas Operations	Investments UK Operations (i)	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)	(77)	-	243	166
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	-	-
Net Option Premiums Paid/(Received) (c)	8	14	1	23
Change in Fair Value Due to Valuation Methodology Changes (d)	3	-	-	3
Changes in Fair Value of Risk Management Contracts (e)	48	(45)	(30)	(27)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(1)	-	-	(1)
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2004	$267	$(26)	$(32)	209
Net Cash Flow Hedge Contracts (g)				(31)
Net Risk Management Liabilities Held for Sale, included in the totals above (h)				18
Ending Net Risk Management Assets at June 30, 2004				$196

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed in detail within the following pages.
(h) See Note 7 for discussion of Assets Held for Sale.
(i) During 2004, we began to unwind our risk management contracts within the U.K. as part of our planned divestiture of our UK Operations. We completed the sale of substantially all of our operations and assets in the Investments-UK Operations segment in July 2004.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of June 30, 2004

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Current Assets	$560	$229	$194	$983
Non Current Assets	368	153	56	577
Total Assets	$928	$382	$250	$1,560
Current Liabilities	$(451)	$(239)	$(233)	$(923)
Non Current Liabilities	(210)	(169)	(49)	(428)
Total Liabilities	$(661)	$(408)	$(282)	$(1,351)
Total Net Assets (Liabilities), excluding Cash Flow Hedges	$267	$(26)	$(32)	$209

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of June 30, 2004

	Risk Management Contracts*	Cash Flow Hedges	Assets Held for Sale	Consolidated
		(in millions)		
Current Assets	$983	$82	$(251)	$814
Non Current Assets	577	6	(56)	527
Total Assets	$1,560	$88	$(307)	$1,341
Current Liabilities	$(923)	$(105)	$276	$(752)
Non Current Liabilities	(428)	(14)	49	(393)
Total Liabilities	$(1,351)	$(119)	$325	$(1,145)
Total Net Assets (Liabilities)	$209	$(31)	$18	$196

***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 (liabilities) 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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in millions)			
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$(28)	$(32)	$1	$4	$-	$-	$(55)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	88	44	12	7	3	-	154
Prices Based on Models and Other Valuation Methods (b)	7	55	14	27	20	45	168
Total	$67	$67	$27	$38	$23	$45	$267
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$36	$42	$(2)	$1	$-	$-	$77
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(51)	14	-	-	-	-	(37)
Prices Based on Models and Other Valuation Methods (b)	1	(48)	(8)	(3)	(3)	(5)	(66)
Total	$(14)	$8	$(10)	$(2)	$(3)	$(5)	$(26)
Investments - UK Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$-	$-	$-	$-	$-	$-	$-
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(4)	(31)	6	-	-	-	(29)
Prices Based on Models and Other Valuation Methods (b)	(3)	-	-	-	-	-	(3)
Total	$(7)	$(31)	$6	$-	$-	$-	$(32)
Consolidated:							
Prices Actively Quoted - Exchange Traded Contracts	$8	$10	$(1)	$5	$-	$-	$22
Prices Provided by Other External Sources - OTC Broker Quotes (a)	33	27	18	7	3	-	88
Prices Based on Models and Other Valuation Methods (b)	5	7	6	24	17	40	99
Total	$46	$44	$23	$36	$20	$40	$209

(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 June 30, 2004

Domestic	Transaction Class	Market/Region	Tenor

--------	-----------------	-------------	-----
			(in months)
Natural Gas	Futures	NYMEX Henry Hub	66
	Physical Forwards	Gulf Coast, Texas	18
	Swaps	Gas East - Northeast, Mid-continent Gulf Coast, Texas	18
	Swaps	Gas West - Rocky Mountains, West Coast	18
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	PJM	30
	Physical Forwards	Cinergy	42
	Physical Forwards	PJM	42
	Physical Forwards	NYPP	30
	Physical Forwards	NEPOOL	18
	Physical Forwards	ERCOT	18
	Physical Forwards	TVA	-
	Physical Forwards	Com Ed	18
	Physical Forwards	Entergy	8
	Physical Forwards	PV, NP15, SP15, MidC, Mead	54
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	30
Emissions	Credits	SO2	30
Coal	Physical Forwards	PRB, NYMEX, CSX	30
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 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, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. 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 June 30, 2004.

Information on energy merchant activities is presented separately from interest rate, foreign currency risk management 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 Loss
On the Balance Sheet as of June 30, 2004

	Accumulated Other be Comprehensive Loss After Tax (a)	Portion Expected to Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power, Gas and Coal	$(4)	$-
Foreign Currency	(10)	(9)
Interest Rate	(5)	(3)
Total	$(19)	$(12)

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2004

	Power, Gas and Coal	Foreign Currency	Interest Rate	Consolidated
		(in millions)		
Beginning Balance, December 31, 2003	$(65)	$(20)	$(9)	$(94)
Changes in Fair Value (c)	5	(4)	-	1
Reclassifications from AOCI to Net Income (d)	56	14	4	74
Ending Balance, June 30, 2004	$(4)	$(10)	$(5)	$(19)

(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 assess independently 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 $44 million, we believe that credit exposure with any one counterparty is not material to our financial condition at June 30, 2004. At June 30, 2004, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 21% expressed in terms of net MTM assets and net receivables. The concentration in non-investment grade credit quality was largely due to coal exposures related to financially weak domestic coal counterparties and coal and freight exposures related to our U.K. investments. These exposures were driven by the continued high levels of prices for coal and freight. As of June 30, 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	$877	$138	$739	1	$75
Split Rating	24	2	22	2	20
Non-Investment Grade	325	171	154	3	94
No External Ratings:					
Internal Investment Grade	345	9	336	1	58
Internal Non-Investment Grade	176	41	135	2	43
Total	$1,747	$361	$1,386	9	$290

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 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 megawatthours 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 June 30, 2004

	Remainder 2004	2005	2006
Estimated Plant Output Hedged	90%	89%	87%

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 June 30, 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

Six Months Ended June 30, 2004 (in millions)				Twelve Months Ended December 31, 2003 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$19	$7	$2	$11	$19	$7	$4

The 2004 High VaR was due to the wind-down of the London risk management activities. These activities were concluded in March 2004. The 2004 High VaR, excluding London activities, was approximately $8 million.

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

CCRO VaR Metrics

	June 30, 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	$13	$26	$73	$7
99% Confidence Level, One-Day Holding Period	$5	$11	$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 $903 million at June 30, 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, cash flows 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 and Six Months Ended June 30, 2004 and 2003
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
REVENUES				
Utility Operations	$2,501	$2,672	$5,080	$5,359
Gas Operations	777	638	1,429	1,571
Other	90	140	200	305
TOTAL	3,368	3,450	6,709	7,235
EXPENSES				
Fuel for Electric Generation	734	759	1,428	1,492
Purchased Electricity for Resale	87	214	170	370
Purchased Gas for Resale	701	650	1,286	1,528
Maintenance and Other Operation	972	946	1,836	1,835
Depreciation and Amortization	320	331	639	642
Taxes Other Than Income Taxes	176	157	360	345
TOTAL	2,990	3,057	5,719	6,212
OPERATING INCOME	378	393	990	1,023
Other Income (Expense), Net	51	50	91	116
INTEREST AND OTHER CAPITAL CHARGES				
Interest	199	197	398	389
Preferred Stock Dividend Requirements of Subsidiaries	1	3	3	6
Minority Interest in Finance Subsidiary	-	8	-	17
TOTAL	200	208	401	412
INCOME BEFORE INCOME TAXES	229	235	680	727
Income Taxes	78	58	240	257
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	151	177	440	470
DISCONTINUED OPERATIONS (Net of Tax)	(51)	(2)	(58)	(48)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)				
Accounting for Risk Management Contracts	-	-	-	(49)
Asset Retirement Obligations	-	-	-	242
NET INCOME	$100	$175	$382	$615
AVERAGE NUMBER OF SHARES OUTSTANDING	396	395	396	376
EARNINGS PER SHARE				
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	$0.38	$0.45	$1.11	$1.25
Discontinued Operations	(0.13)	(0.01)	(0.15)	(0.12)
Cumulative Effect of Accounting Changes	-	-	-	0.51
TOTAL EARNINGS PER SHARE (BASIC AND DILUTED)	$0.25	$0.44	$0.96	$1.64
CASH DIVIDENDS PAID PER SHARE	$0.35	$0.35	$0.70	$0.95

=======	=======	=======	=======

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$858	$976
Other Cash Deposits	208	206
Accounts Receivable:		
Customers	1,044	1,155
Accrued Unbilled Revenues	560	596
Miscellaneous	75	83
Allowance for Uncollectible Accounts	(133)	(124)
Total Receivables	1,546	1,710
Fuel, Materials and Supplies	1,192	991
Risk Management Assets	814	766
Margin Deposits	128	119
Other	119	129
TOTAL	4,865	4,897
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,663	15,112
Transmission	6,223	6,130
Distribution	10,078	9,902
Other (including gas, coal mining and nuclear fuel)	3,613	3,572
Construction Work in Progress	967	1,305
TOTAL	36,544	36,021
Less: Accumulated Depreciation and Amortization	14,363	14,004
TOTAL-NET	22,181	22,017
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,521	3,548
Securitized Transition Assets	670	689
Spent Nuclear Fuel and Decommissioning Trusts	1,013	982
Investments in Power and Distribution Projects	214	212
Goodwill	78	78
Long-term Risk Management Assets	527	494
Other	724	733
TOTAL	6,747	6,736
Assets Held for Sale	2,055	2,761
Assets of Discontinued Operations	-	333
TOTAL ASSETS	$35,848	$36,744

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,165	$1,337
Short-term Debt	596	326
Long-term Debt Due Within One Year*	1,865	1,779
Risk Management Liabilities	752	631
Accrued Taxes	762	620
Accrued Interest	199	207
Customer Deposits	462	379
Other	627	703
TOTAL	6,428	5,982
NON-CURRENT LIABILITIES		
Long-term Debt*	11,533	12,322
Long-term Risk Management Liabilities	393	335
Deferred Income Taxes	4,144	3,957
Regulatory Liabilities and Deferred Investment Tax Credits	2,277	2,259
Asset Retirement Obligations and Nuclear Decommissioning	693	651
Employee Benefits and Pension Obligations	676	667
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	171	176
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	72	76
Deferred Credits and Other	542	508
TOTAL	20,501	20,951
Liabilities Held for Sale	775	1,710
Liabilities of Discontinued Operations	-	166
TOTAL LIABILITIES	27,704	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. . . . . .404,657,511 / 404,016,413		
(8,999,992 shares were held in treasury at June 30, 2004 and December 31, 2003)	2,630	2,626
Paid-in Capital	4,193	4,184
Retained Earnings	1,595	1,490
Accumulated Other Comprehensive Income (Loss)	(335)	(426)
TOTAL	8,083	7,874
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$35,848	$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 Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in millions)	
OPERATING ACTIVITIES		
Net Income	$382	$615
Plus: Discontinued Operations	58	48
Income from Continuing Operations	440	663
Adjustments for Noncash Items:		
Depreciation and Amortization	639	642
Deferred Income Taxes	92	42
Deferred Investment Tax Credits	(13)	(16)
Cumulative Effect of Accounting Changes	-	(193)
Amortization of Deferred Property Taxes	(2)	-
Amortization of Cook Plant Restart Costs	-	20
Mark-to-Market of Risk Management Contracts	50	(33)
Over/Under Fuel Recovery	(4)	85
Change in Other Non-Current Assets	38	(94)
Change in Other Non-Current Liabilities	90	(13)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	167	(9)
Accounts Payable	(180)	(136)
Fuel, Materials and Supplies	(196)	(40)
Customer Deposits and Risk Management Collateral	83	167
Taxes Accrued	140	62
Interest Accrued	(8)	(16)
Other Current Assets	(1)	(60)
Other Current Liabilities	(73)	(221)
Net Cash Flows From Operating Activities	1,262	850
INVESTING ACTIVITIES		
Construction Expenditures	(697)	(639)
Change in Other Cash Deposits, Net	(2)	23
Investment in Discontinued Operations, Net	-	(716)
Proceeds from Sale of Assets	131	41
Other	(7)	3
Net Cash Flows Used For Investing Activities	(575)	(1,288)
FINANCING ACTIVITIES		
Issuance of Common Stock	11	1,142
Issuance of Long-term Debt	263	3,472
Change in Short-term Debt, Net	188	(2,218)
Retirement of Long-term Debt	(986)	(1,407)
Retirement of Preferred Stock	(4)	(2)
Retirement of Minority Interest	-	(225)
Dividends Paid on Common Stock	(277)	(342)
Net Cash Flows From (Used For) Financing Activities	(805)	420
Net Decrease in Cash and Cash Equivalents	(118)	(18)
Cash and Cash Equivalents at Beginning of Period	976	1,088
Cash and Cash Equivalents at End of Period	$858	$1,070
Net Increase in Cash and Cash Equivalents from Discontinued Operations	$2	$15
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	13	23
Cash and Cash Equivalents from Discontinued Operations - End of Period	$15	$38

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest, net of capitalized amounts, was $378 million and $366 million in 2004 and 2003, respectively. Cash paid (received) for income taxes was $(43) million and $155 million in 2004 and 2003, respectively. Noncash acquisitions under capital leases were $27 million and $0 in 2004 and 2003, respectively.

In connection with the disposition of AEP Coal in April 2004 the buyer assumed $11 million of non-current liabilities.

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 Six Months Ended June 30, 2004 and 2003
(in millions)
(Unaudited)

	Common Stock		Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
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				(342)		(342)
Common Stock Expense			(35)			(35)
Other			(8)	3		(5)
TOTAL						7,859
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					23	23
Cash Flow Hedges					(100)	(100)
Securities Available for Sale					1	1
Minimum Pension Liability					15	15
NET INCOME				615		615
TOTAL COMPREHENSIVE INCOME						554
JUNE 30, 2003	404	$2,626	$4,182	$2,275	$(670)	$8,413
DECEMBER 31, 2003	404	$2,626	$4,184	$1,490	$(426)	$7,874
Issuance of Common Stock	1	4	7			11
Common Stock Dividends				(277)		(277)
Other			2			2
TOTAL						7,610
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					(1)	(1)
Cash Flow Hedges					75	75
Minimum Pension Liability					17	17
NET INCOME				382		382
TOTAL COMPREHENSIVE INCOME						473
JUNE 30, 2004	405	$2,630	$4,193	$1,595	$(335)	$8,083

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in millions)	
TOTAL LONG-TERM DEBT OUTSTANDING		
First Mortgage Bonds	$556	$822
Defeased TCC First Mortgage Bonds (a)	112	118
Installment Purchase Contracts	1,936	2,026
Notes Payable	1,409	1,518
Senior Unsecured Notes	7,840	7,997
Securitization Bonds	718	746
Notes Payable to Trust	254	331
Equity Unit Senior Notes	345	345
Long-term DOE Obligation (b)	227	226
Other Long-term Debt	41	21
Equity Unit Contract Adjustment Payments	14	19
Unamortized Discount (net)	(54)	(68)
TOTAL	13,398	14,101
Less Portion Due Within One Year	1,865	1,779
TOTAL LONG-TERM PORTION	$11,533	$12,322

(a) On May 7, 2004, we deposited cash and treasury securities of $124.5 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $103 million are included in Other Cash Deposits and $22 million in Other Non-current Assets in the Consolidated Balance Sheets at June 30, 2004. Trust fund assets are restricted for exclusive use in retiring the First Mortgage Bonds.

(b) 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 $259 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Consolidated Balance Sheets at June 30, 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 June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(in millions)			
Other Income:				
Interest and Dividend Income	$5	$8	$11	$13
Equity Earnings	3	1	10	2
Nonoperating Revenue	28	38	57	66
Gain on Sale of REPs (Mutual Energy Companies)	-	-	-	39
Other	56	52	85	89
Total Other Income	92	99	163	209
Other Expense:				
Nonoperating Expenses	22	34	46	60
Other	19	15	26	33
Total Other Expense	41	49	72	93
Total Other Income (Expense), Net	$51	$50	$91	$116

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	June 30, 2004	December 31, 2003
	(in millions)	
Foreign Currency Translation Adjustments	$109	$110
Unrealized Losses on Securities Available for Sale	(1)	(1)
Unrealized Losses on Cash Flow Hedges	(19)	(94)
Minimum Pension Liability	(424)	(441)
Total	$(335)	$(426)

At June 30, 2004, we expect to reclassify approximately $12 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect net income. Two years is the maximum period over which an exposure to a variability in future commodity or foreign currency related cash flows is hedged with SFAS 133 designated contracts. Approximately $1 million of the fair value of cash flow hedges at June 30, 2004 are hedging interest rate variability on debt past two years. 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

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 Mining 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	27.7	3.0	1.5	32.2
Foreign Currency Translation	-	-	0.3	0.3
Liabilities Incurred	-	-	17.7	17.7
Liabilities Settled	-	-	(11.3)	(11.3)
Revisions in Cash Flow Estimates	-	-	15.0	15.0
Asset Retirement Obligation Liability at June 30, 2004 including Held for Sale	798.6	78.4	76.3	953.3
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project (a)	(227.0)	-	-	(227.0)
U.K. Plants (b)	-	-	(44.8)	(44.8)
Asset Retirement Obligation Liability at June 30, 2004	$571.6	$78.4	$31.5	$681.5

(a) We have signed an agreement to sell TCC's share of South Texas Project (see Note 7 for additional information).
(b) We closed on the sale of our U.K. plants in late July 2004 (see Note 7 for additional information).

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

As of June 30, 2004 and December 31, 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $885 million and $845 million, respectively, of which $754 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 $131 million and $125 million as of June 30, 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. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

We implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which we previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. The Medicare subsidy reduced our FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million. The tax-free subsidy reduced the second quarter's net periodic postretirement benefit cost by a total of $7 million, including $3 million of amortization of the actuarial gain, $1 million of reduced service cost, and $3 million of reduced interest cost on the APBO. After adjustment to capitalization of employee benefits costs as a cost of construction projects, $5 million of this tax-free cost reduction remained to increase the second quarter's net income.

The effect of implementing FSP FAS 106-2 on the first quarter of 2004 is as follow:

Three Months Ended March 31, 2004	Earnings in Millions	Earnings Per Share
Originally Reported	$278	$0.70
Effect of Medicare Subsidy	5	0.02
Restated	$283	$0.72

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including discontinued operations, business combinations, liabilities and equity, revenue recognition, accounting for equity-based compensation, pension plans, asset retirement obligations, earnings per share calculations, fair value measurements, 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 and regulatory proceedings at the FERC and at several state commissions. 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 Reconciliation

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 from July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory.

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: (1) 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 (2) 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.

In December 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 in January 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 May 2004, the PUCT reversed its position on the inclusion of MTM amounts in the allocation of system sales margins and remanded the case to the ALJ. As a result, TNC recorded an additional provision of $12 million in the second quarter of 2004 resulting in an over-recovery balance of $7 million at June 30, 2004.

On July 2, 2004, the parties to the MTM remand proceeding filed a "Stipulation of Fact." All parties agreed to the amount of the remanded issue. If the amounts included in the "Stipulation of Fact" are approved, the over-recovery balance will be reduced to $4 million. We expect the PUCT to issue its final order in this proceeding in August 2004.

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 from July 1998 through December 2001.

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. In May 2004, the PUCT accepted most of the ALJ's recommendations. The PUCT rejected the ALJ's recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. Hearings are scheduled in October 2004 for the remand issue. As a result of the PUCT's acceptance of the ALJ's recommendations and the PUCT's remand decision in the TNC case regarding the inclusion of MTM amounts in the allocation of AEP's net system sales margins, TCC increased its provision by $47 million in the second quarter of 2004. The over-recovery balance and the provisions total $210 million including interest at June 30, 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 and cash flows. 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 the SPP. This reconciliation covers the period from 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 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%. In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a non-unanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request to $41 million. The ALJs that heard the case issued their recommendations on July 2, 2004, including a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded for additional evidence. On July 15, 2004, the PUCT agreed to remand this issue to the ALJs. In addition, the PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. The ALJs' recommendations reduce TCC's existing rates by a range of $33 million to $43 million depending on the final resolution of the amount of consolidation tax savings. TCC filed exceptions to the ALJs' recommendations on July 21, 2004. The PUCT is expected to issue its decision in September 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates, revenues, 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 its 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, it 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 if a rate reduction is ordered, would adversely impact results of operations and cash flows.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the Corporation Commission of the State of Oklahoma (OCC) seeking to recover these costs over a period of 18 months. 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 that $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 between and among AEP operating companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and could more than offset the $44 million 2002 reallocation. The intervenor and the OCC Staff also believed trading margins were allocated incorrectly and that a reallocation by the intervenors of such margins would reduce PSO's recoverable fuel by approximately $6.8 million for 2000 and $10.7 million for 2001, while under the OCC Staff method, the amount for 2001 would be $8.8 million. The intervenor and the OCC Staff also recommend recalculation of fuel for years subsequent to 2001 using the same methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were the jurisdiction of the OCC or the FERC because they relate to the FERC-approved agreements. As a result, the ALJ ordered that the jurisdictional issue be briefed by the parties. PSO is required to file its brief by September 1, 2004. Subject to decisions by the OCC as to jurisdiction, a hearing date has been set for January 2005. 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

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

$33 million of RTO formation and integration costs and related carrying charges through June 30, 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 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 prudently incurred deferred RTO formation/integration 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 as these companies file rate cases. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo.

In August 2004, we intend to file an application with FERC dividing the RTO formation/integration costs between payments made to PJM and all other costs. We will subsequently request that the payments made directly to PJM be recovered from all users of PJM's transmission and that the balance of the deferred costs be recovered from load-serving entities within the area served by the AEP East companies' owned transmission (AEP zone). Most of the amount recoverable in the AEP zone will be paid by the AEP East companies since it will be attributable to their internal load. The amount to be recovered in the AEP zone is approximately one-half of the deferred costs. In our August application, we will seek permission to delay the amortization of the AEP zone deferred amounts until they are recoverable from users of the transmission system including our retail customers or, as an alternative, to use a long amortization period that extends beyond the rate freezes or caps.

The AEP East companies are scheduled to join PJM in October 2004, although there are pending proceedings in Virginia 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 or a long enough amortization period to allow for the opportunity for recovery in the East retail jurisdictions. 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 project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or a long amortization period or the FERC or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM. In July 2004, after reaching a unanimous agreement with intervenors to settle the RTO issues in Virginia, the settlement agreement was submitted to the Virginia SCC. The settlement provides for approval of APCo's application to join PJM in exchange for a small annual revenue credit to customers through 2010, or the effective date of rates established in a new base rate case, some service curtailment provisions and annual reporting requirements.

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 approved the agreement in May 2004 and the FERC approved the settlement in June 2004.

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

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. The FERC issued an order related to this matter in June 2004 affirming its preliminary findings. Virginia requested a stay of the FERC order, which was denied, and Virginia now has requested a stay in the courts.

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 August 27, 2003, the IURC ordered that certain parties must negotiate the appropriate action on I&M's fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant outage issues). The fixed fuel adjustment charge capped fuel recoveries. In an agreement in connection with AEP's planned corporate separation, I&M agreed, contingent on AEP implementing the corporate separation, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although we have not corporately separated, certain parties believe the fixed fuel adjustment charge should continue. Negotiations with the parties to resolve 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 to actual fuel costs following the resolution of issues in the corporate separation agreement. The IURC also issued an order that reopened the corporate separation docket to investigate issues related to the corporate separation agreement. On July 15, 2004, we filed a fuel factor for the period October 2004 through March 2005. If the IURC reinstates a fixed fuel adjustment factor, capping the fuel revenues, results of operations and cash flows would be adversely affected if fuel costs are under-recovered.

Michigan 2004 Fuel Recovery Plan

A 1999 Michigan Public Service Commission's (MPSC) 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. 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 occurred on March 10, 2004 and a MPSC order is expected during the second half of 2004. On June 4, 2004, an ALJ recommended that SO_2 and NO_x costs be excluded. We filed our exceptions on June 18, 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 cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

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 (MBSSO) 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 (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO or the CBP. Customers who make no choice will be served pursuant to the CBP. The companies were granted a waiver from making the required MBSSO/CBP filing, as a result of their rate stabilization plan filing.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008. The plan is intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. 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 prior to December 31, 2005 as permitted by the Ohio Act, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. Any additional 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 governmentally mandated, mainly environmental, capital expenditures. Hearings were held in June 2004. Briefings were completed in July and the cases are pending before the PUCO. 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. Through June 30, 2004, we incurred $72 million, and accordingly, we deferred $32 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 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The 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.

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 PROCEEDINGS

The 2004 true-up proceedings will determine the amount and recovery of:
o net stranded generation plant costs and generation-related regulatory assets (stranded plant costs),
o carrying charges on stranded plant costs at a weighted cost of capital from January 2002 (the commencement date of retail competition),
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 TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later. TNC filed its 2004 true-up proceeding in June 2004.

Summary of TCC True-up Items

Recorded	Amount at June 30, 2004
	(in millions)
Stranded Generation Plant Costs (a)	$1,074
Unsecuritized Transition Regulatory Asset (a)	194
Unrefunded Excess Earnings (b)	(19)
Other	(46)
Amount Subject to Future Securitization	1,203
Wholesale Capacity Auction True-up (c)	480
Retail Clawback (d)	(30)
Deferred Over-recovered Fuel (e)	(210)
Other Recoverable Amounts	240
Total Recorded 2004 True-up Balance (f)	$1,443

(a) See "Stranded Costs and Generation-Related Regulatory Assets" section below for additional information on this item.
(b) See "Unrefunded Excess Earnings" section below for additional information on this item.
(c) See "Wholesale Capacity Auction True-up" section below for additional information on this item.
(d) See "Retail Clawback" section below for additional information on this item.

(e) See "Fuel Balance Recoveries" section below for additional information on this item.
(f) See "Stranded Cost Recovery" section below for summary of this balance.

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 elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. 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. Based on the prices established by the sales, discussed below, TCC's stranded costs from the sale of TCC's generation assets and remaining generation-related net regulatory assets are estimated to be $1.3 billion ($1,074 million and $194 million, described later in this section) before accrual of any applicable carrying charges.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generation capacity in Texas with a net book value of $1.9 billion at June 30, 2004. We received bids for all of TCC's generation plants. In January 2004, TCC agreed to sell its 7.81% 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% ownership interest 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 to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion and the fossil and hydro plants. We have received a notice from co-owners of Oklaunion and STP exercising their right of first refusal; therefore, SEC approval will be required. The original unaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and that the co-owners' rights of first refusal are void. Approval of the sale of STP from the Nuclear Regulatory Commission is required. On July 1, 2004, we completed the sale of the other coal, gas and hydro plants for approximately $425 million, net of adjustments. The completion of the sales of STP and Oklaunion plants is expected to occur in 2004, subject to the rights of first refusal and the necessary regulatory approvals. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. TCC will file its 2004 true-up proceeding with the PUCT after the completion of the sale of the generation assets.

After the 2004 true-up proceeding, TCC may recover stranded costs and other true-up amounts through distribution rates as a competition transition charge and may seek to issue securitization revenue bonds for its stranded plant costs and remaining generation net regulatory assets. The cost of the securitization bonds is recovered through distribution rates as a separate transition charge. We recognized an impairment of TCC's generation assets in December 2003 as a regulatory asset. At June 30, 2004, this regulatory asset was approximately $1,074 million. The recovery of this regulatory asset and the remaining $194 million of generation-related net regulatory assets will be subject to review and approval by the PUCT as a stranded plant cost in the 2004 true-up proceeding.

Carrying Charges On Recoverable Stranded Costs

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the 2004 true-up proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the companies, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and the PUCT should address whether the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs. Industrial intervenors have filed a motion for rehearing with the Supreme Court which has not been decided.

The PUCT has indicated that it will consider the Supreme Court's decision in hearings to be held for another utility in September 2004. The decision in that proceeding could have an impact on TCC. Since the impact of these future PUCT proceedings cannot be determined at this time, TCC has not recorded the carrying charge as a regulatory asset through June 30, 2004.

Wholesale Capacity Auction True-up

Texas Legislation required 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. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. 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. The PUCT issued a written order in March 2004 that established TNC's unrecovered fuel balance for the ERCOT service territory. Various parties, including TNC, requested rehearing of the PUCT's order. In May 2004, the PUCT reversed certain prior rulings resulting in TNC having a final fuel over-recovery balance of approximately $7 million. TNC's 2004 true-up proceeding, filed in June 2004, will be updated to reflect the balance after the PUCT issues a final fuel order. TNC has provided for all to-date disallowances pending receipt of the final order. Management is unable to predict the amount of TNC's fuel over-recovery which will be included in its 2004 true-up proceedings.

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 May 2004, the PUCT remanded TCC's fuel proceeding to the ALJ. TCC has provided $210 million for its over-recovery balance at June 30, 2004. TCC has provided for all to-date disallowances pending receipt of a final order. 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 had 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 ($19 million at June 30, 2004). 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 ultimate 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. Based upon customer information filed by the unaffiliated company which operates as the affiliated REP for TCC and TNC, we updated the estimated retail clawback regulatory liability in May 2004. At June 30, 2004, AEP's retail clawback regulatory liability was $37 million ($30 million related to TCC and $7 million related to TNC).

TNC 2004 True-up Filing

In June 2004, TNC filed its 2004 true-up proceeding including the fuel reconciliation balance and the retail clawback calculation. The amount of deferred fuel, presently an over-recovery balance of $7 million, remains under review by the PUCT and is subject to possible revision. The retail clawback regulatory liability was adjusted in the second quarter of 2004 to $7 million (TNC's allocated portion of the REP's retail clawback) reflecting the number of customers served on January 1, 2004. The PUCT has deferred this proceeding pending the resolution of the final fuel proceeding.

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, through a non-bypassable competition transition charge in the regulated rates. TCC may also seek to securitize the approved stranded plant costs and generation-related net regulatory assets that were not previously recovered through a prior securitization and the non-bypassable transition charge. The annual costs of securitization are recovered through the non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds.

TCC's recorded net regulatory asset for stranded cost in the 2004 true-up proceeding is approximately $1.4 billion. We estimate that TCC's 2004 true-up filing will exceed the total of its recorded net regulatory asset. Management expects that the 2004 true-up proceeding will be contentious and could possibly result in disallowances.

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 net regulatory assets, 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 optional general base rate changes and an opportunity for recovery, through a separate rate mechanism, 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) potential uninsured losses, (4) merger litigation, (5) shareholder lawsuits, (6) California lawsuits, (7) Cornerstone 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 June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The

NOV expands the number of alleged "modifications" undertaken at the Muskingum River, Cardinal, Conesville and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA is expected to file a motion to amend its complaint, and, to the extent that motion seeks to expand the scope of the pending litigation, the AEP subsidiaries will oppose that motion.

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 was scheduled for July 2004, but has been postponed until January 2005 to facilitate further settlement negotiations.

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. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals, which issued a briefing order requiring the case to be fully briefed by late September 2004.

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 any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, 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.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input valve, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input valve in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, and the referenced recordkeeping and reporting requirements and heat input valve at Welsh. We are preparing additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other unaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of two special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. Management believes the actions are without merit and intends to vigorously defend against the claims.

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. As discussed in Note 7, TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

OPERATIONAL

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease for up to 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on 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.

At June 30, 2004, Juniper's acquisition costs for the Facility totaled $520 million, and we estimate total costs for the completed Facility to be approximately $525 million, funded through long-term debt financing of $494 million and equity of $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. For the initial 5-year lease term, the base lease rental is equal to the interest on Juniper's debt financing at a variable rate indexed to three-month LIBOR (1.61% as of June 30, 2004) plus 100 basis points, plus a fixed return on Juniper's equity investment in the Facility and certain other fixed amounts. Consequently, as LIBOR increases, the base rental payments under the Juniper Lease will also increase.

The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's obligations as a liability of $520 million. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

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 (Tractebel SA) 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. Management believes the PPA is enforceable. The litigation is now in the discovery phase.

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

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 (the 10.5 BCF and 55 BCF described in the preceding 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. Also 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 the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value.

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, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements.

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. The parties are currently in non-binding court-sponsored mediation.

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. The parties are currently in non-binding court-sponsored mediation.

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 these lawsuits or their impact on our results of operations, cash flows or financial condition.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas Retail Electric Provider (REP), filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

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. 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 responded to that request. The case is in the initial pleading stage with our response to the complaint currently due on September 13, 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 future results of operations, financial condition or cash flows. 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. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. 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. We plan to present evidence to demonstrate that we do not possess market power in geographic areas where we sell wholesale power.

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 June 30, 2004, the maximum future payments for all the LOCs were approximately $244 million with maturities ranging from July 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 the Fort Lupton, Colorado IPP (also known as Thermo), 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. Our exposure for these payments will expire upon the sale of Fort Lupton in the third quarter of 2004.

We had a letter of credit for Orange Cogeneration, a cogeneration plant located in Bartow, Florida, that expired upon its sale in July 2004. See Note 7.

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 L.P. (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 was released from its guarantee for Mulberry, a cogeneration plant located in Bartow, Florida, when it was sold in July 2004. See Note 7.

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 June 30, 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. SWEPCo does not have an ownership interest in Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 and during the first six months of 2004, we entered into several sale agreements. These sale agreements include indemnifications with a maximum exposure of approximately $258 million. There are no material liabilities recorded for any indemnifications entered into during 2003 or the first six months 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 June 30, 2004, the maximum potential loss for these lease agreements was approximately $35 million ($23 million, net of tax) 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 June 30, 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

DISPOSITION 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 in March 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 COMPLETED DURING SECOND QUARTER 2004

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

In February 2004, we signed an agreement to sell LIG Pipeline Company, which includes 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 LIG Pipeline Company and its assets for $76.2 million was completed in April 2004. The effect of the sale on the second quarter 2004 results of operations was not significant.

Results of operations of LIG Pipeline Company were reclassified as of December 31, 2003 as Discontinued Operations. The assets and liabilities of LIG Pipeline Company were classified on our Balance Sheet as held for sale until the sale was complete. Beginning with our second quarter 2004 financial statements, the assets and liabilities of LIG Pipeline Company are shown as Assets of Discontinued Operations and Liabilities of Discontinued Operations for all periods presented.

See Louisiana Intrastate Gas (LIG) in Discontinued Operations section of this note for previous impairments taken on the LIG assets and information regarding remaining LIG assets still held for sale.

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 $11.1 million in future reclamation liability. AEP has retained an estimated $36.7 million in future reclamation liabilities. The sale closed in April 2004 and the effect of the sale on second quarter 2004 results of operations was not significant. The assets and liabilities of AEP Coal that were held for sale have been included in Assets Held for Sale and Liabilities Held for Sale in our Consolidated Balance Sheets at December 31, 2003.

DISPOSITIONS COMPLETED OR SCHEDULED TO BE COMPLETED DURING SECOND HALF 2004

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. As a result of the 2004 true-up proceeding, if we are unable to recover all or a portion of our requested costs (see Note 4), any unrecovered costs could have a material adverse effect on our results of operations, cash flows and possibly financial condition.

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, except in the case that our true-up proceedings, as described above, do not allow for recovery of our stranded costs.

Oklaunion Power Station

In April 2004, we signed an agreement to sell TCC's 7.81 percent share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, we received notice from the two co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. The sale is currently being challenged by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one of two co-owners has exceeded its legal authority and has requested that the court declare the one co-owner's exercise of its right of first refusal void. The unrelated party further argues that the second of the two co-owner's exercise of its right of first refusal is not timely and invalid. We expect that this legal issue will be resolved and that the planned sale will close by the end of 2004.

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. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. We expect the sale to close before the end of 2004 subject to necessary regulatory approval.

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. The sale was completed in July 2004 for approximately $425 million, net of adjustments. The sale did not have a significant effect on our results of operations during the second quarter 2004.

Independent Power Producers (Investments - Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). Our two Colorado investments include a 47.75 percent interest in Brush II, a 68-megawatt, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50 percent interest in Thermo, a 272-megawatt, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments include a 46.25 percent interest in Mulberry, a 120-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50 percent interest in Orange, a 103-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, 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 the two 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 for the year ended December 31, 2003.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a sales price of $156 million, subject to closing adjustments. An additional pre-tax impairment of $1.6 million was recorded in June 2004 (recorded to Other Income (Expense), Net) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004, resulting in a pre-tax gain of approximately $100 million, generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded during July 2004. The sale of the Ft. Lupton, Colorado plant is awaiting Federal Energy Regulatory Commission approval and is expected to close during the third quarter 2004, with no significant effect on results of operations during the third quarter.

U.K. Generation (Investments - UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942.3 million and assumption of certain liabilities. Since December 2001, we also made additional equity contributions to fund our UK Operations. 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 (Loss) that have 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.

In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge) that were held-for-sale as described above, related coal assets, and a number of related commodities contracts for approximately $456 million. We are still determining the final impact from the sale on our third quarter results of operations. Although the final sales price will be subject to closing adjustments, expected to be determined during the third quarter 2004, we believe that a gain on sale, which would be included in discontinued operations, may result.

Excess Real Estate (Investments - Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, TX obtained through our merger with CSW in June 2000. One prospective buyer executed an option to purchase the building. Sale of the facility was projected by second quarter 2003 and an estimated 2002 pre-tax loss on disposal of $15.7 million was recorded, based on the option sale price. The estimated loss was included in Asset Impairments on AEP's Consolidated Statements of Operations in 2002. In December 2003, we recorded an additional pre-tax impairment of $6 million recorded in Maintenance and Other Operation on our Consolidated Statements of Operations. The original prospective buyer did not complete their purchase of the building by the end of 2003, and thus, the asset no longer qualified for held for sale status. The building was then reclassified to held and used status as of December 31, 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. This resulted in the asset again being classified as held for sale in the second quarter of 2004. An additional pre-tax impairment of $2.5 million was recorded to Maintenance and Other Operation expense during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. The property asset of $9.5 million at June 30, 2004 and $12.0 million at December 31, 2003 has been classified on AEP's Consolidated Balance Sheets as held for sale. Although the negotiations entered into in June 2004 did not yield a final signed purchase agreement, active efforts to sell the building continue and we do not expect the sale to have a significant effect on our results of operations.

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 for all periods presented. Results of operations of these businesses have been reclassified for the three and six month periods ended June 30, 2004 and 2003, as shown in the following table:

For the three months ended June 30, 2004 and 2003:

	Eastex	Pushan Power Plant	LIG	U.K. Generation	Total
			(in millions)		
2004 Revenue	$-	$-	$4	$34	$38
2004 Pretax Income (Loss)	-	-	2	(80)	(78)
2004 Income (Loss) After-Tax	-	(1)	2	(52)	(51)
2003 Revenue	15	12	150	61	238
2003 Pretax Income (Loss)	(9)	-	3	4	(2)
2003 Income (Loss) After-Tax	(7)	-	1	4	(2)

For the six months ended June 30, 2004 and 2003:

	Eastex	Pushan Power Plant	LIG	U.K. Generation	Total
			(in millions)		
2004 Revenue	$-	$10	$164	$75	$249
2004 Pretax Income (Loss)	-	9	1	(99)	(89)
2004 Income (Loss) After-Tax	-	5	1	(64)	(58)
2003 Revenue	46	27	353	112	538
2003 Pretax Income (Loss)	(23)	-	6	(36)	(53)
2003 Income (Loss) After-Tax	(15)	-	4	(37)	(48)

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

	Pushan Power Plant	LIG (excluding Jefferson Island)	Total
		(in millions)	
As of December 31, 2003			
Current Assets	$24	$49	$73
Property, Plant and Equipment, Net	142	109	251
Goodwill	-	1	1
Other	-	8	8
Total Assets of Discontinued Operations	$166	$167	$333
Current Risk Management Liabilities	$-	$15	$15
Current Liabilities	26	42	68
Long-term Debt	20	-	20
Deferred Credits and Other	57	6	63
Total Liabilities of Discontinued Operations	$103	$63	$166

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)

As a result of our 2003 decision to exit our non-core businesses, we actively marketed LIG Pipeline Company (gas pipeline and processing operations) and Jefferson Island Storage & Hub, L.L.C. (JISH) (gas storage) together as a combined operation. For the year ended December 31, 2003, LIG's assets (including those of JISH) were classified as held for sale and their operations where shown under Discontinued Operations. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. 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 LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale was completed in April 2004 and the impact on results of operations in the second quarter of 2004 was not significant (see LIG Pipeline Company and its Subsidiaries in Dispositions Completed During Second Quarter 2004 for additional information). Management continues its efforts to market JISH. The assets and liabilities of LIG (not including JISH) are classified as Assets of Discontinued Operations and Liabilities of Discontinued Operations 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. The gas storage assets of JISH remain held for sale as of June 30, 2004. It is anticipated that the sale of JISH will take place by the end of the year, and that it will not have a significant impact on our results of operation's.

U.K. Generation

See U.K. Generation section under Dispositions Completed or Scheduled to be Completed During Second Half 2004 for information regarding the sale of U.K. Generation assets in July 2004.

ASSETS HELD FOR SALE

The assets and liabilities of the entities held for sale at June 30, 2004 and December 31, 2003 are as follows:

June 30, 2004	U.K. Generation	Texas Plants	Excess Real Estate	Jefferson Island	Total
			(in millions)		
Assets:					
Current Risk Management Assets	$251	$-	$-	$-	$251
Other Current Assets	372	58	-	3	433
Property, Plant and Equipment, Net	115	796	10	63	984
Regulatory Assets	-	51	-	-	51
Decommissioning Trusts	-	132	-	-	132
Goodwill	-	-	-	14	14
Long-term Risk Management Assets	56	-	-	-	56
Other	117	-	-	17	134
Total Assets Held for Sale	$911	$1,037	$10	$97	$2,055
Liabilities:					
Current Risk Management Liabilities	$276	$-	$-	$-	$276

Other Current Liabilities	156	-	-	2	158
Long-term Risk Management Liabilities	49	-	-	-	49
Regulatory Liabilities	-	9	-	-	9
Asset Retirement Obligations	45	227	-	-	272
Employee Pension Obligations	10	-	-	-	10
Deferred Credits and Other	1	-	-	-	1
	-----	-------	----	----	-------
Total Liabilities Held for Sale	$537	$236	$-	$2	$775
	=====	=======	====	====	=======

December 31, 2003	AEP Coal	U.K. Generation	Texas Plants	Excess Real Estate	Jefferson Island	Total
			(in millions)			
Assets:						
Current Risk Management Assets	$-	$560	$-	$-	$-	$560
Other Current Assets	6	685	57	-	1	749
Property, Plant and Equipment, Net	13	99	797	12	62	983
Regulatory Assets	-	-	49	-	-	49
Decommissioning Trusts	-	-	125	-	-	125
Goodwill	-	-	-	-	14	14
Long-term Risk Management Assets	-	274	-	-	-	274
Other	-	6	-	-	1	7
	----	-------	-------	----	----	-------
Total Assets Held for Sale	$19	$1,624	$1,028	$12	$78	$2,761
	====	=======	=======	====	====	=======
Liabilities:						
Current Risk Management Liabilities	$-	$767	$-	$-	$-	$767
Other Current Liabilities	-	221	-	-	4	225
Long-term Risk Management Liabilities	-	435	-	-	-	435
Regulatory Liabilities	-	-	9	-	-	9
Asset Retirement Obligations	11	29	219	-	-	259

Employee Pension Obligations	-	12	-	-	-	12
Deferred Credits and Other	3	-	-	-	-	3
Total Liabilities Held for Sale	$14	$1,464	$228	$-	$4	$1,710

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 and six months ended June 30, 2004 and 2003:

Three Months ended June 30, 2004 and 2003:	U.S. Pension Plans 2004	U.S. Pension Plans 2003	U.S. Other Postretirement Benefit Plans 2004	U.S. Other Postretirement Benefit Plans 2003
	(in millions)			
Service Cost	$21	$20	$10	$11
Interest Cost	57	59	30	33
Expected Return on Plan Assets	(73)	(80)	(20)	(17)
Amortization of Transition (Asset) Obligation	1	(2)	7	6
Amortization of Net Actuarial Loss	4	3	9	13
Net Periodic Benefit Cost	$10	$-	$36	$46

Six Months ended June 30, 2004 and 2003:	U.S. Pension Plans 2004	U.S. Pension Plans 2003	U.S. Other Postretirement Benefit Plans 2004	U.S. Other Postretirement Benefit Plans 2003
	(in millions)			
Service Cost	$43	$40	$20	$21
Interest Cost	114	117	59	65
Expected Return on Plan Assets	(146)	(159)	(41)	(32)
Amortization of Transition (Asset) Obligation	1	(4)	14	14
Amortization of Net Actuarial Loss	8	5	18	26
Net Periodic Benefit Cost (Credit)	$20	$(1)	$70	$94

In accordance with our implementation of FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," as discussed in Note 2, accounting for the Medicare subsidy reduced expected 2004 postretirement benefit cost by $29 million. As a result, expected cash flows for 2004 employer contributions to U.S. other postretirement benefit plans have been reduced by $29 million from the $180 million disclosed at December 31, 2003. Including an additional $19 million reduction related to refining earlier estimates, we currently expect to contribute approximately $132 million to our U.S. other postretirement benefit plans during 2004.

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's U.K. plants

Investments - Other
o Bulk commodity barging operations, windfarms, independent power producers 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 and six months ended June 30, 2004 and 2003 and balance sheet information as of June 30, 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
				(in millions)			
Three Months Ended June 30, 2004							
Revenues from:							
External Customers	$2,501	$777	$-	$90	$-	$-	$3,368
Other Operating Segments	43	40	-	19	(2)	(100)	-
Total Revenues	2,544	817	-	109	(2)	(100)	3,368
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	183	(4)	-	(3)	(25)	-	151
Discontinued Operations, Net of Tax	-	2	(52)	(1)	-	-	(51)
Net Income (Loss)	183	(2)	(52)	(4)	(25)	-	100
As of June 30, 2004							
Total Assets	$31,235	$2,207	$800	$1,519	$13,090	$(13,003)	$35,848
Assets Held for Sale and Assets of Discontinued Operations	1,037	97	911	10	-	-	2,055

* 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
				(in millions)			
Three Months Ended June 30, 2003							
Revenues from:							
External Customers	$2,672	$638	$-	$140	$-	$-	$3,450
Other Operating Segments	(7)	37	-	28	4	(62)	-
Total Revenues	2,665	675	-	168	4	(62)	3,450
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	225	(25)	-	(20)	(3)	-	177
Discontinued Operations, Net of Tax	-	1	4	(7)	-	-	(2)
Net Income (Loss)	225	(24)	4	(27)	(3)	-	175
As of December 31, 2003							
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	1,028	245	1,624	185	12	-	3,094

* 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
			(in millions)				
Six Months Ended June 30, 2004							
Revenues from:							
External Customers	$5,080	$1,429	$-	$200	$-	$-	$6,709
Other Operating Segments	69	39	-	50	4	(162)	-
Total Revenues	5,149	1,468	-	250	4	(162)	6,709
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	486	(13)	-	1	(34)	-	440
Discontinued Operations, Net of Tax	-	1	(64)	5	-	-	(58)
Net Income (Loss)	486	(12)	(64)	6	(34)	-	382
As of June 30, 2004							
Total Assets	$31,235	$2,207	$800	$1,519	$13,090	$(13,003)	$35,848
Assets Held for Sale and Assets of Discontinued Operations	1,037	97	911	10	-	-	2,055

* 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.

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other*	Reconciling Adjustments	Consolidated
				(in millions)			
Six Months Ended June 30, 2003							
Revenues from:							
External Customers	$5,359	$1,571	$-	$305	$-	$-	$7,235
Other Operating Segments	12	52	-	43	7	(114)	-
Total Revenues	5,371	1,623	-	348	7	(114)	7,235
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	531	(43)	-	-	(18)	-	470
Discontinued Operations, Net of Tax	-	4	(37)	(15)	-	-	(48)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	767	(61)	(58)	(15)	(18)	-	615
As of December 31, 2003							
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	1,028	245	1,624	185	12	-	3,094

* 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 issued and retired during the first six months of 2004 are shown in the table below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
CSPCo	Installment Purchase Contracts	$44	Variable	2038
OPCo	Financing Obligation	6	5.77	2024
PSO	Installment Purchase Contracts	34	Variable	2014
PSO	Senior Unsecured Notes	50	4.70	2009
SWEPCo	Installment Purchase Contracts	54	Variable	2019
SWEPCo	Installment Purchase Contracts	41	Variable	2011
SWEPCo	Financing Obligation	14	5.77	2024
Non-Registrant:				
AEP Subsidiary	Notes Payable	23	Variable	2009
AEP Subsidiaries	Other Debt	2	Variable	Various
Total Issuances		$268 (a)		

(a) Amount indicated on statement of cash flows of $263 million is net of issuance costs.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Retirements:				
AEP	Senior Unsecured Notes	$57	5.25	2015
AEP	Senior Unsecured Notes	10	5.375	2010
APCo	First Mortgage Bonds	45	7.125	2024
APCo	Installment Purchase Contracts	40	5.45	2019
CSPCo	First Mortgage Bonds	11	7.60	2024
CSPCo	Installment Purchase Contracts	44	6.25	2020
I&M	First Mortgage Bonds	30	7.20	2024
I&M	First Mortgage Bonds	25	7.50	2024
OPCo	Installment Purchase Contracts	50	6.85	2022
OPCo	Notes Payable	2	6.27	2009
OPCo	Notes Payable	3	6.81	2008
OPCo	First Mortgage Bonds	10	7.30	2024
OPCo	Senior Unsecured Notes	140	7.375	2038
PSO	Notes Payable to Trust	77	8.00	2037
PSO	Installment Purchase Contracts	34	4.875	2014
SWEPCo	Installment Purchase Contracts	12	6.90	2004

SWEPCo	Installment Purchase Contracts	12	6.00	2008
SWEPCo	Installment Purchase Contracts	17	8.20	2011
SWEPCo	Installment Purchase Contracts	54	7.60	2019
SWEPCo	First Mortgage Bonds	80	6.875	2025
SWEPCo	First Mortgage Bonds	40	7.75	2004
SWEPCo	Notes Payable	3	4.47	2011
SWEPCo	Notes Payable	2	Variable	2008
TCC	First Mortgage Bonds	6	6.625	2005
TCC	Securitization Bonds	29	3.54	2005
TNC	First Mortgage Bonds	24	6.125	2004
Non-Registrant:				
AEP Subsidiaries	Notes Payable	40	6.73	2004
AEP Subsidiaries	Notes Payable and Other Debt	114	Variable	2007-2017
Total Retirements		$1,011 (b)		

(b) Amount indicated on statement of cash flows of $986 million does not include $25 million related to retirement of debt of a discontinued operation.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Defeasance:				
TCC	First Mortgage Bonds	$27	7.25	2004
TCC	First Mortgage Bonds	66	6.625	2005
TCC	First Mortgage Bonds	19	7.125	2008
Total Defeased		$112 (c)		

(c) Trust fund assets for defeasance of First Mortgage Bonds of $103 million are included in Other Cash Deposits and $22 million in Other Non-current Assets in the Consolidated Balance Sheets at June 30, 2004. Trust fund assets are restricted for exclusive use in retiring the First Mortgage Bonds.

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.

Net Income decreased $262 thousand for the second quarter of 2004 compared with the second quarter of 2003 and decreased $231 thousand for the six months ended June 30, 2004 compared with the six months ended June 30, 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.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income decreased $141 thousand for the second quarter of 2004 compared with the second quarter of 2003. The largest variances related to:

o A $3 million decrease in Operating Revenue as a result of decreased recoverable expenses in accordance with the unit power agreements.
o A $4 million decrease in Fuel for Electric Generation expense. This decrease is primarily due to a 16% decrease in MWH generation as a result of both planned and forced outages.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were (19.7)% and (5.8)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004, flow-through differences, and state income taxes.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income decreased $445 thousand for the six months ended June 30, 2004 compared with the six months ended June 30, 2003. The largest variances related to:

o An $8 million decrease in Operating Revenue as a result of decreased recoverable expenses in accordance with the unit power agreements.
o A $4 million increase in Maintenance expense as a result of increased planned boiler inspections and forced repairs.
o A $13 million decrease in Fuel for Electric Generation expense. This decrease is primarily due to a 23% decrease in MWH generation as a result of both planned and forced outages.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were (13.9)% and (16.1)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to higher flow-through differences and state income taxes offset by lower pre-tax income in 2004.

Off-balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements. 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 policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements. 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 "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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 and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended 2004	Three Months Ended 2003	Six Months Ended 2004	Six Months Ended 2003
	(in thousands)			
OPERATING REVENUES	$56,348	$59,568	$111,630	$119,996
OPERATING EXPENSES				
Fuel for Electric Generation	25,036	29,237	46,434	59,634
Rent - Rockport Plant Unit 2	17,071	17,071	34,142	34,142
Other Operation	2,665	2,442	5,155	4,991
Maintenance	2,790	2,287	8,190	3,938
Depreciation and Amortization	5,772	5,665	11,506	11,286
Taxes Other Than Income Taxes	942	604	1,886	1,395
Income Taxes	699	748	1,397	1,245
TOTAL	54,975	58,054	108,710	116,631
OPERATING INCOME	1,373	1,514	2,920	3,365
Nonoperating Income	5	19	29	21
Nonoperating Expenses	80	25	149	242
Nonoperating Income Tax Credits	947	845	1,804	1,739
Interest Charges	739	585	1,271	1,319
NET INCOME	$1,506	$1,768	$3,333	$3,564

STATEMENTS OF RETAINED EARNINGS
For the Three and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended 2004	Three Months Ended 2003	Six Months Ended 2004	Six Months Ended 2003
	(in thousands)			
BALANCE AT BEGINNING OF PERIOD	$22,006	$18,788	$21,441	$18,163
Net Income	1,506	1,768	3,333	3,564
Cash Dividends Declared	1,261	1,172	2,523	2,343
BALANCE AT END OF PERIOD	$22,251	$19,384	$22,251	$19,384

The common stock of AEGCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$667,819	$645,251
General	4,039	4,063
Construction Work in Progress	5,419	24,741
TOTAL	677,277	674,055
Accumulated Depreciation	355,855	351,062
TOTAL - NET	321,422	322,993
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	23,996	24,748
Fuel	24,061	20,139
Materials and Supplies	5,508	5,419
Prepayments	21	-
TOTAL	53,586	50,306
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,614	4,733
Asset Retirement Obligations	1,022	928
Deferred Property Taxes	2,134	502
Other Deferred Charges	436	464
TOTAL	8,206	6,627
TOTAL ASSETS	$383,333	$380,045

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	22,251	21,441
Total Common Shareholder's Equity	46,685	45,875
Long-term Debt	44,815	44,811
TOTAL	91,500	90,686
CURRENT LIABILITIES		
Advances from Affiliates	42,758	36,892
Accounts Payable:		
General	897	498
Affiliated Companies	13,286	15,911
Taxes Accrued	10,527	6,070
Interest Accrued	911	911
Obligations Under Capital Leases	69	87
Rent Accrued - Rockport Plant Unit 2	4,963	4,963
Other	98	-
TOTAL	73,509	65,332
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	23,983	24,329
Regulatory Liabilities:		
Asset Removal Costs	27,863	27,822
Deferred Investment Tax Credits	47,921	49,589
SFAS 109 Regulatory Liability, Net	14,531	15,505
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	102,690	105,475
Obligations Under Capital Leases	166	182
Asset Retirement Obligations	1,170	1,125
TOTAL	218,324	224,027
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$383,333	$380,045

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$3,333	$3,564
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	11,506	11,286
Deferred Income Taxes	(1,319)	(2,158)
Deferred Investment Tax Credits	(1,668)	(1,668)
Deferred Property Taxes	(1,632)	(1,573)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(2,785)	(2,785)
Changes in Certain Assets and Liabilities:		
Accounts Receivable	752	(4,174)
Fuel, Materials and Supplies	(4,011)	4,213
Accounts Payable	(2,226)	(2,939)
Taxes Accrued	4,457	3,806
Change in Other Assets	(93)	(751)
Change in Other Liabilities	154	884
Net Cash Flows From Operating Activities	6,468	7,705
INVESTING ACTIVITIES		
Construction Expenditures	(9,811)	(4,012)
Net Cash Flows Used For Investing Activities	(9,811)	(4,012)
FINANCING ACTIVITIES		
Change in Advances from Affiliates	5,866	(1,350)
Dividends Paid	(2,523)	(2,343)
Net Cash Flows From (Used For) Financing Activities	3,343	(3,693)
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 for interest net of capitalized amounts was $1,138,000 and $1,186,000 and for income taxes was $570,000 and $2,448,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to AEGCo's financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to AEGCo. The footnotes begin on page L-1.

Results of Operations

Net Income decreased $99 million for 2004 year-to-date, and $64 million for the second quarter. The three major factors driving the decline for both periods are; the decreased revenues associated with establishing regulatory assets in Texas, the provision for refunds of fuel charges, and the decrease in retail delivery revenue due mainly to milder weather. These items accounted for a $99 million decrease year-to-date and a $70 million decrease for the quarter. The cessation of depreciation on plants held for sale partially offset these declines.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income decreased $73 million primarily due to:

o Decreased revenues associated with establishing regulatory assets in Texas of $52 million in 2003 (see "Texas Restructuring" in Note 4). These revenues did not continue after 2003.
o Increased provisions for rate refunds of $37 million due to fuel reconciliation issues (see "TCC Fuel Reconciliation" in Note 3).
o Decreased retail delivery revenues of $19 million driven primarily by a decrease in cooling degree-days of 23%.
o Decreased system sales, including those to REPs, of $88 million due mainly to lower KWH sales of 36% due to customer choice in Texas and a small decrease in the overall average price per KWH.
o Decreased Reliability Must Run (RMR) revenues from ERCOT of $4 million, which includes both a fixed cost component decrease of $8 million and fuel recovery increase of $4 million.
o Decreased Qualified Scheduling Entity (QSE) fees of $3 million due mainly to one REP not using TCC as their QSE in 2004.
o Decreased margins of $16 million resulting from risk management activities.
o Increased Other Operation expenses of $10 million due mainly to $3 million increase of ERCOT-related transmission expense and affiliated ancillary services; $2 million higher customer related expenses; increased emission allowance expense and administrative and support expense of $3 million.
o Increased Taxes Other than Income Taxes of $3 million mainly due to increased property taxes.

The decrease in Operating Income was partially offset by:

o Net decreases in fuel and purchased electricity on a combined basis of $91 million. KWH's purchased decreased 86% while the per unit cost increased 1%. Although the KWH generated increased 16%, generating costs increased 22% attributable mostly to higher prices for natural gas offset in part by both units of STP being on line in 2004 whereas in 2003 only one unit was operating.
o Increased revenues from ERCOT of $10 million for various services, including balancing energy.
o Increased transmission revenue of $1 million due mainly to affiliated OATT and ancillary services.
o Decreased Depreciation and Amortization expense of $25 million due mainly to the cessation of depreciation on Texas plants classified as "Held For Sale."

Other Impacts on Earnings

Nonoperating Income increased $4 million primarily as a result of increased income of $8 million related to risk management activities offset in part by $4 million lower non-utility revenues associated with energy-related construction projects for third parties.

Nonoperating Expense decreased $3 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties offset in part by an increase in donations.

Interest charges decreased $3 million primarily due to the defeasance of $112 million of First Mortgage Bonds and the deferral of the interest cost as a cost of the sale of generation assets as well as other financing activities.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 94.2% and 33.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to pre-tax income becoming a loss in 2004 and lower state income taxes.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income decreased $110 million primarily due to:

o Decreased revenues associated with establishing regulatory assets in Texas of $108 million in 2003 (see "Texas Restructuring" in Note 4). These revenues did not continue after 2003.
o Increased provisions for rate refunds of $23 million due to fuel reconciliation issues (see "TCC Fuel Reconciliation" in Note 3).
o Decreased system sales, including those to REPs, of $165 million due mainly to lower KWH sales of 33% due to customer choice in Texas and a small decrease in the overall average price per KWH.
o Decreased revenues from ERCOT of $4 million for various services, including balancing energy.
o Decreased retail delivery revenues of $22 million driven by a decrease of KWH of 3% due in large part to a decrease in cooling degree-days of 16%.
o Decreased RMR revenues from ERCOT of $9 million, which includes both a fuel recovery decrease of $7 million and a fixed cost component decrease of $2 million.
o Decreased QSE fees of $8 million due mainly to one REP not using TCC as their QSE in 2004.
o Decreased margins from risk management activities of $15 million.
o Increased Other Operation expenses of $18 million due mainly to $8 million increase of ERCOT-related transmission expense and affiliated ancillary services; $2 million increase of production expense including emission allowances; $2 million increase in customer related expense; and an increase of $4 million of administrative and support expense.

The decrease in Operating Income was partially offset by:

o Net decreases in fuel and purchased electricity on a combined basis of $163 million. KWH purchased decreased 87% while the per unit cost increased 8%. The KWH generated increased 19% and per unit costs decreased 8% attributable mostly to the fact that both units of STP were on line in 2004.
o Increased transmission revenue of $11 million due mainly to affiliated OATT (including a $7.6 million 2004 true-up) and ancillary services.
o Decreased Depreciation and Amortization expense of $42 million due mainly to the cessation of depreciation on Texas plants classified as "Held For Sale."

Other Impacts on Earnings

Nonoperating Income increased $6 million primarily as a result of increased income of $9 million related to risk management activities offset in part by $5 million lower non-utility revenues associated with energy-related construction projects for third parties.

Nonoperating Expense decreased $3 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties offset in part by an increase in donations.

Interest charges decreased $2 million primarily due to the defeasance of $112 million of First Mortgage Bonds and the deferral of the interest cost as a cost of the sale of generation assets as well as other financing activities.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 18.2% and 34.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004 and lower state income taxes.

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 six months ended June 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$760	$807
Cash flow from (used for):		
Operating activities	118,414	186,201
Investing activities	(163,279)	(23,912)
Financing activities	49,915	(162,937)
Net increase (decrease) in cash and cash equivalents	5,050	(648)
Cash and cash equivalents at end of period	$5,810	$159

Operating Activities

Cash Flows From Operating Activities in 2004 were $118 million primarily due to Net Income, as explained above, Taxes Accrued, Accounts Payable and Changes in Other Liabilities offset in part by Deferred Property Tax and Accounts Receivable, Net.

Investing Activities

Investing expenditures in 2004 were $163 million due primarily to $49 million in construction expenditures focused on improved service reliability projects for transmission and distribution systems, and $117 million in cash deposits for future long-term debt retirement.

Financing Activities

Cash used for financing activities in 2004 reduced Long-term Debt, paid dividends and was offset by Advances to Affiliates.

Financing Activity

Long-term debt issuances, retirements and defeasance during the first six months of 2004 were:

Issuances

None

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$ 6,195	6.625	2005
Securitization Bonds	28,809	3.540	2005

Defeasance

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$27,400	7.25	2004
First Mortgage Bonds	65,763	6.625	2005
First Mortgage Bonds	18,581	7.125	2008

Significant Factors

We made progress on our planned divestiture of all our generation assets by (1) announcing in January 2004 that we had signed an agreement to sell our 7.81% 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) closing on the sale of our remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro plant for approximately $425 million, net of closing adjustments. Subject to certain issues that have arisen relating to co-owners' rights of first refusal, we expect the sales of our share of Oklaunion and South Texas Project to close before the end of 2004. There could, however, be potential delays in receiving appropriate regulatory approvals and clearances which may delay the closing. The sale of our remaining generation assets was completed in July 2004. We will file with the Public Utility Commission of Texas to recover net stranded costs associated with the sales pursuant to Texas restructuring legislation.

Nuclear Decommissioning

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion on factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(2,867)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	45
Change in Fair Value Due to Valuation Methodology Changes (d)	110
Changes in Fair Value of Risk Management Contracts (e)	(1,881)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	7,349
Net Cash Flow Hedge Contracts (g)	(15,162)
Total MTM Risk Management Contract Net Liabilities at June 30, 2004	$(7,813)

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$(277)	$27	$(1)	$88	$-	$-	$(163)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(913)	580	115	-	-	-	(218)
Prices Based on Models and Other Valuation Methods (b)	6,481	451	(33)	87	187	557	7,730
Total	$5,291	$1,058	$81	$175	$187	$557	$7,349

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$(1,828)
Changes in Fair Value (a)	(8,941)
Reclassifications from AOCI to Net Income (b)	(473)
Ending Balance June 30, 2004	$(11,242)

(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 $11,145 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$71	$161	$80	$40	$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 $189 million and $206 million at June 30, 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 OPERATIONS
For the Three and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$256,964	$439,049	$525,822	$821,179
Sales to AEP Affiliates	12,896	43,397	31,026	89,625
TOTAL	269,860	482,446	556,848	910,804
OPERATING EXPENSES				
Fuel for Electric Generation	20,806	21,430	43,912	48,769
Fuel from Affiliates for Electric Generation	59,977	44,911	100,176	83,200
Purchased Electricity for Resale	16,468	116,654	26,554	188,776
Purchased Electricity from AEP Affiliates	1,938	7,210	6,011	18,772
Other Operation	77,977	68,283	153,418	135,678
Maintenance	23,709	21,811	39,113	37,910
Depreciation and Amortization	28,879	53,867	57,976	99,947
Taxes Other Than Income Taxes	23,157	19,783	45,214	42,762
Income Taxes (Credits)	(6,388)	31,894	5,618	66,377
TOTAL	246,523	385,843	477,992	722,191
OPERATING INCOME	23,337	96,603	78,856	188,613
Nonoperating Income	12,061	7,901	24,163	18,063
Nonoperating Expenses	2,648	5,637	7,756	10,832
Nonoperating Income Tax Expense	880	240	860	798
Interest Charges	32,211	35,040	65,340	67,022
Income (Loss) Before Cumulative Effect of Accounting Change	(341)	63,587	29,063	128,024
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	122
NET INCOME (LOSS)	(341)	63,587	29,063	128,146
Preferred Stock Dividend Requirements	61	61	121	121
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$(402)	$63,526	$28,942	$128,025

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(60,401)		(60,401)
Preferred Stock Dividends			(121)		(121)
TOTAL					1,040,612
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(747)	(747)
NET INCOME			128,146		128,146
TOTAL COMPREHENSIVE INCOME					127,399
JUNE 30, 2003	$55,292	$132,606	$1,054,020	$(73,907)	$1,168,011
DECEMBER 31, 2003	$55,292	$132,606	$1,083,023	$(61,872)	$1,209,049
Common Stock Dividends			(48,000)		(48,000)
Preferred Stock Dividends			(121)		(121)
TOTAL					1,160,928
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(9,414)	(9,414)
Minimum Pension Liability				(2,466)	(2,466)
NET INCOME			29,063		29,063
TOTAL COMPREHENSIVE INCOME					17,183
JUNE 30, 2004	$55,292	$132,606	$1,063,965	$(73,752)	$1,178,111

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$-	$-
Transmission	776,784	767,970
Distribution	1,402,159	1,376,761
General	225,610	221,354
Construction Work in Progress	51,586	58,953
TOTAL	2,456,139	2,425,038
Accumulated Depreciation and Amortization	713,376	695,359
TOTAL - NET	1,742,763	1,729,679
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,340	1,302
Bond Defeasance Funds	21,773	-
Other Investments	-	4,639
TOTAL	23,113	5,941
CURRENT ASSETS		
Cash and Cash Equivalents	5,810	760
Other Cash Deposits	158,729	65,122
Advances to Affiliates	-	60,699
Accounts Receivable:		
Customers	189,128	146,630
Affiliated Companies	64,321	78,484
Accrued Unbilled Revenues	21,920	23,077
Allowance for Uncollectible Accounts	(2,306)	(1,710)
Materials and Supplies	13,705	11,708
Risk Management Assets	13,636	22,051
Margin Deposits	245	3,230
Prepayments and Other Current Assets	10,119	6,770
TOTAL	475,307	416,821
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,100	3,249
Wholesale Capacity Auction True-up	480,000	480,000
Unamortized Loss on Reacquired Debt	8,606	9,086
Designated for Securitization	1,262,049	1,253,289
Deferred Debt - Restructuring	11,937	12,015
Other	123,090	133,913
Securitized Transition Assets	669,942	689,399
Long-term Risk Management Assets	2,797	7,627
Deferred Charges	71,248	55,554
TOTAL	2,632,769	2,644,132
Assets Held for Sale - Texas Generation Plants	1,037,138	1,028,134
TOTAL ASSETS	$5,911,090	$5,824,707

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	1,063,965	1,083,023
Accumulated Other Comprehensive Income (Loss)	(73,752)	(61,872)
Total Common Shareholder's Equity	1,178,111	1,209,049
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholder's Equity	1,184,051	1,214,989
Long-term Debt	1,627,705	2,053,974
TOTAL	2,811,756	3,268,963
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	629,118	237,651
Advances From Affiliates	72,341	-
Accounts Payable:		
General	97,642	90,004
Affiliated Companies	84,952	74,209
Customer Deposits	5,878	1,517
Taxes Accrued	98,396	67,018
Interest Accrued	42,440	43,196
Risk Management Liabilities	22,657	17,888
Obligation Under Capital Leases	420	407
Other	20,063	23,248
TOTAL	1,073,907	555,138
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,233,508	1,244,912
Long-term Risk Management Liabilities	1,589	2,660
Regulatory Liabilities:		
Asset Removal Costs	99,900	95,415
Deferred Investment Tax Credits	109,875	112,479
Deferred Fuel Costs	69,026	69,026
Retail Clawback	29,824	45,527
Other	44,812	56,984
Obligation Under Capital Leases	563	636
Deferred Credits and Other	200,028	144,833
TOTAL	1,789,125	1,772,472
Liabilities Held for Sale - Texas Generation Plants	236,302	228,134
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,911,090	$5,824,707

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$29,063	$128,146
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	(122)
Depreciation and Amortization	57,976	99,947
Deferred Income Taxes	(11,682)	13,369
Deferred Investment Tax Credits	(2,603)	(2,603)
Deferred Property Taxes	(22,440)	(20,100)
Mark-to-Market of Risk Management Contracts	4,593	1,955
Wholesale Capacity Auction True-up	-	(108,400)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(26,582)	(87,691)
Fuel, Materials and Supplies	(3,735)	16,456
Accounts Payable	18,381	83,970
Taxes Accrued	31,378	48,277
Interest Accrued	(756)	(7,610)
Change in Other Assets	3,094	9,644
Change in Other Liabilities	41,727	10,963
Net Cash Flows From Operating Activities	118,414	186,201
INVESTING ACTIVITIES		
Construction Expenditures	(49,311)	(56,013)
Change in Other Cash Deposits, Net	(93,607)	32,101
Change in Bond Defeasance Funds and Other	(20,361)	-
Net Cash Flows Used For Investing Activities	(163,279)	(23,912)
FINANCING ACTIVITIES		
Change in Short-term Debt - Affiliates	-	(650,000)
Issuance of Long-term Debt	-	792,027
Retirement of Long-term Debt	(35,004)	(66,230)
Change in Advances to Affiliates	133,040	(178,212)
Dividends Paid on Common Stock	(48,000)	(60,401)
Dividends Paid on Cumulative Preferred Stock	(121)	(121)
Net Cash Flows From (Used For) Financing Activities	49,915	(162,937)
Net Increase (Decrease) in Cash and Cash Equivalents	5,050	(648)
Cash and Cash Equivalents at Beginning of Period	760	807
Cash and Cash Equivalents at End of Period	$5,810	$159

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $61,529,000 and $72,918,000 and for income taxes was $(7,067,000) and $7,803,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TCC's consolidated financial statements are combined with the notes to financial statements for other 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 decreased $7 million for 2004 year-to-date, and $10 million for the second quarter. The year-to-date decrease was driven by lower margins from risk management activities and lower retail delivery revenues in Texas. These same items drive the quarterly decline along with a provision for rate refunds from fuel reconciliation proceedings.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income decreased by $12 million primarily due to:

o Increased provision for rate refunds of $13 million due to fuel reconciliation issues (see "TNC Fuel Reconciliation" in Note 3).
o Decreased margins from risk management activities of $8 million.
o Decreased retail delivery revenues of $3 million due partly to a 13% decline in cooling degree-days.
o Decreased system sales, including those to REPs, of $16 million due mainly to both lower KWH sales of 17% and a small decrease in the overall average price per KWH sold.
o Decrease of Reliability Must Run (RMR) revenues from ERCOT of $1 million which include both fuel recovery and a fixed cost component.
o Increased Taxes Other than Income Taxes of $2 million resulting mainly from higher accrued property taxes.

The decrease in Operating Income was partially offset by:

o Decreased fuel and purchased power on a combined basis of $15 million. KWH generation increased 16%, while the generation cost per KWH increased 4% due primarily to increases in the price of natural gas. KWH purchased declined 9%, and the average cost per KWH purchased decreased 37%.
o Revenues from ERCOT increased $4 million for various services, including balancing energy, due mainly to prior years adjustments made by ERCOT recorded in 2003.
o Increased wholesale revenues of $2 million due to higher fuel revenue, as the pricing is linked to average fuel cost.
o Increased Transmission revenue of $1 million, due mainly to affiliated ancillary services.
o Decreased Other Operation expenses of $3 million, primarily due to proceeds of $1 million for the sale of emission allowances; decreased production expense of approximately $2 million due to the elimination of the RMR status for the San Angelo Power Station - Unit 1; and decreased employee related expenses.

Other Impacts on Earnings

Nonoperating Income decreased $2 million as a result of a $5 million decrease in non-utility revenues associated with energy-related construction projects for third parties, offset in part by an increase of $3 million related to risk management activities.

Nonoperating Expense decreased $5 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 32.6% and 35.4% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004 and lower state income taxes.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income decreased by $5 million primarily due to:

o Decreased system sales, including those to REPs, of $44 million due mainly to both lower KWH sales of 24% due to customer choice in Texas and a small decrease in the overall average price per KWH.
o Decreased retail delivery revenues of $3 million due partly to an 11% decline in cooling degree-days.
o Increased provision for rate refunds of $1 million due to fuel reconciliation issues in 2003 (see "TNC Fuel Reconciliation" in Note 3).

o Decreased margins from risk management activities of $9 million.
o Decreased revenues from ERCOT of $1 million for various services, including balancing energy, due mainly to prior year adjustments made by ERCOT and recorded in 2003.
o Increased Taxes Other than Income Taxes of $1 million resulting mainly from higher accrued property taxes.

The decrease in Operating Income was partially offset by:

o Decreased fuel and purchased power on a combined basis of $37 million. KWH purchased declined 31%, and the average cost per KWH purchased decreased 34%. KWH generation increased 6%, while the generation cost per KWH increased 8% due primarily to increases in the price of natural gas.
o Increased Transmission revenue of $8 million, due mainly to prior year adjustments recorded in 2003 for affiliated OATT and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
o Increase of RMR revenues from ERCOT of $4 million, which include both a fuel recovery increase of $6 million and a fixed cost decrease of $2 million.
o Increased wholesale revenues of $1 million due to higher fuel revenue which is linked to average fuel cost pricing.
o Decreased Other Operation expenses of $3 million, primarily due to proceeds of $1 million for the sale of emission allowances, decreased production expense of approximately $2 million due to the elimination of the RMR status for the San Angelo Power Station - Unit 1, as well as decreased employee-related expenses.

Other Impacts on Earnings

Nonoperating Income decreased $2 million primarily as a result of a $5 million decrease in non-utility revenue associated with energy-related construction projects for third parties, offset in part by an increase of $3 million related to risk management activities.

Nonoperating Expense decreased $6 million primarily due to lower non-utility expenses associated with energy-related construction projects for third parties.

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

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 33.7% and 37.1% respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2004 and lower state income taxes.

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 six 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 "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(982)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	20
Change in Fair Value Due to Valuation Methodology Changes (d)	45
Changes in Fair Value of Risk Management Contracts (e)	(1,038)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-

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Total MTM Risk Management Contract Net Assets
2,665
Net Cash Flow Hedge Contracts (g)
(5,083)

Total MTM Risk Management Contract Net Liabilities at June 30, 2004
$(2,418)

========

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changing methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
Prices Actually Quoted - Exchange Traded Contracts	$(111)	$11	$-	$35	$-	$-	$(65)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(231)	233	46	-	-	-	48
Prices Based on Models and Other Valuation Methods (b)	2,180	181	(13)	35	75	224	2,682
Total	$1,838	$425	$33	$70	$75	$224	$2,665

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$(601)
Changes in Fair Value (a)	(3,001)

Reclassifications from AOCI to Net Income (b)	(163)
Ending Balance June 30, 2004	$(3,765)

(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 $3,727 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$29	$65	$32	$16	$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 $31 million and $33 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$88,968	$120,568	$177,680	$216,629
Sales to AEP Affiliates	12,027	16,238	26,745	36,439
TOTAL	100,995	136,806	204,425	253,068
OPERATING EXPENSES				
Fuel for Electric Generation	10,661	8,278	18,161	19,739
Fuel from Affiliates for Electric Generation	12,542	10,917	23,766	17,002
Purchased Electricity for Resale	23,282	26,723	41,305	51,501
Purchased Electricity from AEP Affiliates	544	16,449	4,076	35,794
Other Operation	19,556	22,365	39,937	42,984
Maintenance	5,950	6,012	10,633	10,153
Depreciation and Amortization	9,854	9,723	19,546	19,255
Taxes Other Than Income Taxes	5,293	3,432	10,397	9,465
Income Taxes	2,541	9,664	8,482	14,067
TOTAL	90,223	113,563	176,303	219,960
OPERATING INCOME	10,772	23,243	28,122	33,108
Nonoperating Income	15,632	17,834	29,388	31,305
Nonoperating Expenses	11,962	17,114	22,898	28,681
Nonoperating Income Tax Expense	1,209	142	2,103	481
Interest Charges	5,482	5,899	11,662	10,564
Income Before Cumulative Effect of Accounting Changes	7,751	17,922	20,847	24,687
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	3,071
NET INCOME	7,751	17,922	20,847	27,758
Preferred Stock Dividend Requirements	26	26	52	52
EARNINGS APPLICABLE TO COMMON STOCK	$7,725	$17,896	$20,795	$27,706

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(52)		(52)
TOTAL					175,722
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(309)	(309)
Minimum Pension Liability				(7)	(7)
NET INCOME			27,758		27,758
TOTAL COMPREHENSIVE INCOME					27,442
JUNE 30, 2003	$137,214	$2,351	$94,678	$(31,079)	$203,164
DECEMBER 31, 2003	$137,214	$2,351	$125,428	$(26,718)	$238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(52)		(52)
TOTAL					236,223
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(3,164)	(3,164)
NET INCOME			20,847		20,847
TOTAL COMPREHENSIVE INCOME					17,683
JUNE 30, 2004	$137,214	$2,351	$144,223	$(29,882)	$253,906

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$361,620	$360,463
Transmission	275,081	268,695
Distribution	465,965	456,278
General	120,557	117,792
Construction Work in Progress	25,582	30,199
TOTAL	1,248,805	1,233,427
Accumulated Depreciation and Amortization	469,153	460,513
TOTAL - NET	779,652	772,914
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,181	1,286
TOTAL	1,181	1,286
CURRENT ASSETS		
Cash and Cash Equivalents	1,387	-
Other Cash Deposits	2,297	2,863
Advances to Affiliates	47,984	41,593
Accounts Receivable:		
Customers	70,674	56,670
Affiliated Companies	18,759	28,910
Accrued Unbilled Revenues	3,537	4,871
Miscellaneous	521	3,411
Allowance for Uncollectible Accounts	(85)	(175)
Fuel Inventory	8,852	10,925
Materials and Supplies	8,619	8,866
Risk Management Assets	4,877	10,340
Margin Deposits	87	1,285
Prepayments and Other	1,477	1,834
TOTAL	168,986	171,393
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Fuel Costs	26,680	26,680
Deferred Debt - Restructuring	6,336	6,579
Unamortized Loss on Reacquired Debt	2,967	3,929
Other	2,949	3,332
Long-term Risk Management Assets	1,124	3,106
Deferred Charges	31,671	20,290
TOTAL	71,727	63,916
TOTAL ASSETS	$1,021,546	$1,009,509

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	144,223	125,428
Accumulated Other Comprehensive Income (Loss)	(29,882)	(26,718)
Total Common Shareholder's Equity	253,906	238,275
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholder's Equity	256,263	240,632
Long-term Debt	314,306	314,249
TOTAL	570,569	554,881
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	18,469	42,505
Accounts Payable:		
General	21,748	28,190
Affiliated Companies	44,168	40,601
Customer Deposits	998	161
Taxes Accrued	37,404	22,877
Interest Accrued	5,423	6,038
Risk Management Liabilities	7,780	8,658
Obligations Under Capital Leases	207	203
Other	7,247	9,419
TOTAL	143,444	158,652
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	111,087	113,019
Long-term Risk Management Liabilities	639	1,094
Regulatory Liabilities:		
Asset Removal Costs	83,601	76,740
Deferred Investment Tax Credits	19,333	19,990
Retail Clawback	6,837	11,804
Excess Earnings	14,020	14,262
SFAS 109 Regulatory Liability, Net	12,855	13,655
Other	1,679	1,826
Obligations Under Capital Leases	282	270
Deferred Credits and Other	57,200	43,316
TOTAL	307,533	295,976
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,021,546	$1,009,509

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$20,847	$27,758
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(3,071)
Depreciation and Amortization	19,546	19,255
Deferred Income Taxes	(2,767)	(1,079)
Deferred Investment Tax Credits	(656)	(760)
Deferred Property Taxes	(7,400)	(6,645)
Mark-to-Market of Risk Management Contracts	1,955	(2,905)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	281	24,683
Fuel, Materials and Supplies	2,320	4,308
Accounts Payable	(2,875)	(61,985)
Taxes Accrued	14,527	16,134
Change in Other Assets	(8,931)	(5,976)
Change in Other Liabilities	14,538	12,909
Net Cash Flows From Operating Activities	51,385	22,626
INVESTING ACTIVITIES		
Construction Expenditures	(18,085)	(21,609)
Change in Other Cash Deposits, Net	566	(1,383)
Other	-	595
Net Cash Flows Used For Investing Activities	(17,519)	(22,397)
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	(6,391)	(92,312)
Dividends Paid on Common Stock	(2,000)	(4,970)
Dividends Paid on Cumulative Preferred Stock	(52)	(52)
Net Cash Flows From (Used For) Financing Activities	(32,479)	121
Net Increase in Cash and Cash Equivalents	1,387	350
Cash and Cash Equivalents at Beginning of Period	-	62
Cash and Cash Equivalents at End of Period	$1,387	$412

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $11,139,000 and $5,525,000 and for income taxes was $(412,000) and $(1,305,000) in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS NORTH COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TNC's financial statements are combined with the notes to financial statements for other 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 second quarter of 2004 increased $7 million from the prior year period due to favorable results from risk management activities, increased sales and decreased interest charges partially offset by increased Maintenance expense and Income Taxes.

Net Income for the first six months of 2004 decreased $84 million from the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003 and increased Maintenance and depreciation expenses partially offset by favorable results from risk management activities and decreased interest charges.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income for 2004 decreased $3 million from 2003 primarily due to the following:

o A decrease in off-system sales and transmission revenues totaling $10 million.
o An increase in Maintenance expense of $16 million primarily due to planned maintenance at Amos, Clinch River, and Glen Lyn plants relating to scheduled outages in 2004.
o An $8 million increase in Income Taxes (see "Income Taxes" below).
o A decrease of $4 million in Sales to AEP Affiliates due to decreased power available for sale caused by planned plant outages in 2004.
o An increase in Other Operation expense of $4 million primarily due to increased allocated costs from AEPSC and higher employee-related benefits costs in the second quarter of 2004.

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

o An increase in retail sales of $22 million primarily as a result of increased cooling degree days in the second quarter of 2004.
o An increase of $13 million due to favorable results from risk management activities.
o A net $7 million decrease in Fuel and purchased electricity expense as a $14 million decrease in Fuel expense was partially offset by increased purchased electricity expense. The $14 million decrease in Fuel expense was primarily due to decreased generation and deferred fuel expense partially offset by the increased cost of coal used in generation.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $4 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Interest charges decreased $9 million in the second quarter of 2004 from the prior year period due to reduced interest rates from refunding higher cost debt and increased Allowance for Funds Used During Construction in 2004.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 46.0% and 39.9%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to an investment tax credit adjustment as a result of the Virginia SCC extending the regulatory transition period offset by lower state income taxes.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income for 2004 decreased $28 million from 2003 primarily due to the following:

o A decrease in off-system sales and transmission revenues totaling $6 million.
o An increase in Maintenance expense of $25 million primarily due to planned maintenance at Amos, Clinch River, Glen Lyn and Kanawha River plants relating to scheduled outages in 2004.
o A decrease of $7 million in Sales to AEP Affiliates due to decreased power available for sale caused by planned plant outages in 2004.
o An increase in Depreciation and Amortization expense of $13 million primarily due to reduced expense in 2003 attributable to the adoption of SFAS 143 for regulated operations and to a lesser degree, a greater depreciable base in 2004, which included the addition

of capitalized software costs.
o An increase in Other Operation expense of $10 million primarily due to increased allocated costs from AEPSC and higher employee-related benefits costs in 2004.

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

o An increase in retail sales of $22 million primarily as a result of increased cooling degree days in the second quarter of 2004.
o A net $7 million decrease in Fuel and purchased electricity expense as a $23 million decrease in Fuel expense was partially offset by increased purchased electricity expense. The $23 million decrease in Fuel expense was primarily due to decreased generation and deferred fuel expense partially offset by the increased cost of coal used in generation.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $14 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Interest charges decreased $12 million in the first six months of 2004 from the prior year due to reduced interest rates from refunding higher cost debt and increased Allowance for Funds Used During Construction in 2004.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 40.2% and 37.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to an investment tax credit adjustment as a result of the Virginia SCC extending the regulatory transition period offset by federal income tax adjustments.

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 six months ended June 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$4,561	$4,133
Cash flow from (used for):		
Operating activities	228,942	267,383
Investing activities	(163,031)	(113,170)

Financing activities	(66,841)	(147,840)
Net increase (decrease) in cash and cash equivalents	(930)	6,373
Cash and cash equivalents at end of period	$3,631	$10,506

Operating Activities

Net Cash Flows From Operating Activities in the first six months of 2004 were $229 million versus $267 million in 2003 due to changes in Accounts Receivable and Accounts Payable, as well as increased purchases of emission allowances and increased fuel inventory.

Investing Activities

Net Cash Flows Used For Investing Activities in the first six months of 2004 were $163 million. Current year construction expenditures of $204 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In addition, Changes in Other Cash Deposits, Net of $41 million consisted primarily of monies set aside in 2003 for the retirement of the Installment Purchase Contracts in 2004.

Financing Activities

In the first six months of 2004, we retired $40 million of Installment Purchase Contracts and $45 million of First Mortgage Bonds, paid $50 million in dividends and increased Advances from Affiliates by $69 million.

Financing Activity

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

Issuances

None.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$45,000	7.125	2024
Installment Purchase Contracts	40,000	5.45	2019

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(23,158)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	601
Change in Fair Value Due to Valuation Methodology Changes (d)	835
Changes in Fair Value of Risk Management Contracts (e)	5,166
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	5,782
Total MTM Risk Management Contract Net Assets	57,292
Net Cash Flow Hedge Contracts (g)	(6,972)
DETM Assignment (h)	(27,127)
Total MTM Risk Management Contract Net Assets at June 30, 2004	$23,193

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See Note 17 "Related Party Transactions" 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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(3,646)	$362	$(10)	$1,156	$-	$-	$(2,138)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	16,350	5,240	3,670	1,978	928	-	28,166
Prices Based on Models and Other Valuation Methods (b)	289	5,929	2,754	4,839	4,912	12,541	31,264
Total	$12,993	$11,531	$6,414	$7,973	$5,840	$12,541	$57,292

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be market-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 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)	(2,971)	-	(705)	(3,676)
Reclassifications from AOCI to Net Income (b)	(958)	3	169	(786)
Ending Balance June 30, 2004	$(3,570)	$(180)	$(2,281)	$(6,031)

(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 $2,659 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$936	$2,122	$1,056	$529	$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 $111 million and $102 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$413,383	$389,255	$885,958	$868,588
Sales to AEP Affiliates	51,047	55,496	104,929	112,391
TOTAL	464,430	444,751	990,887	980,979
OPERATING EXPENSES				
Fuel for Electric Generation	98,694	112,680	209,405	232,545
Purchased Electricity for Resale	17,786	15,262	34,430	32,380
Purchased Electricity from AEP Affiliates	87,793	83,805	178,280	164,525
Other Operation	70,576	66,626	138,668	128,741
Maintenance	52,933	36,827	94,253	69,565
Depreciation and Amortization	47,231	46,065	95,144	82,073
Taxes Other Than Income Taxes	23,499	22,272	46,952	47,351
Income Taxes	19,836	12,158	60,276	62,059
TOTAL	418,348	395,695	857,408	819,239
OPERATING INCOME	46,082	49,056	133,479	161,740
Nonoperating Income (Loss)	3,540	(324)	9,087	(4,624)
Nonoperating Expenses	3,596	2,451	6,129	6,309
Nonoperating Income Tax Credit	(1,263)	(2,451)	(1,625)	(6,184)
Interest Charges	25,463	34,096	50,900	63,202
Income Before Cumulative Effect of Accounting Changes	21,826	14,636	87,162	93,789
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	77,257
NET INCOME	21,826	14,636	87,162	171,046
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	798	984	1,621	1,968
EARNINGS APPLICABLE TO COMMON STOCK	$21,028	$13,652	$85,541	$169,078

The common stock of APCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(64,133)		(64,133)
Preferred Stock Dividends			(721)		(721)
Capital Stock Expense		1,247	(1,247)		-
SFAS 71 Reapplication		162			162
TOTAL					1,101,365
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(3,113)	(3,113)
NET INCOME			171,046		171,046
TOTAL COMPREHENSIVE INCOME					167,933
JUNE 30, 2003	$260,458	$718,651	$365,384	$(75,195)	$1,269,298
DECEMBER 31, 2003	$260,458	$719,899	$408,718	$(52,088)	$1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense		1,221	(1,221)		-
TOTAL					1,286,587
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(4,462)	(4,462)
NET INCOME			87,162		87,162
TOTAL COMPREHENSIVE INCOME					82,700
JUNE 30, 2004	$260,458	$721,120	$444,259	$(56,550)	$1,369,287

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,408,222	$2,287,043
Transmission	1,249,901	1,240,889
Distribution	2,033,834	2,006,329
General	302,053	294,786
Construction Work in Progress	321,620	311,884
TOTAL	6,315,630	6,140,931
Accumulated Depreciation and Amortization	2,382,795	2,321,360
TOTAL - NET	3,932,835	3,819,571
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	20,457	20,574
Other Investments	22,938	26,668
TOTAL	43,395	47,242
CURRENT ASSETS		
Cash and Cash Equivalents	3,631	4,561
Other Cash Deposits	705	41,320
Accounts Receivable:		
Customers	136,105	133,717
Affiliated Companies	119,821	137,281
Accrued Unbilled Revenues	23,669	35,020
Miscellaneous	4,302	3,961
Allowance for Uncollectible Accounts	(5,426)	(2,085)
Fuel Inventory	60,580	42,806
Materials and Supplies	87,942	71,978
Risk Management Assets	91,267	71,189
Margin Deposits	3,974	11,525
Prepayments and Other	13,317	13,301
TOTAL	539,887	564,574
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Transition Regulatory Assets	27,590	30,855
SFAS 109 Regulatory Asset, Net	324,233	325,889
Unamortized Loss on Reacquired Debt	19,696	19,005
Other Regulatory Assets	41,658	41,447
Long-term Risk Management Assets	83,507	70,900
Deferred Property Taxes	29,640	35,343
Other Deferred Charges	22,784	22,185
TOTAL	549,108	545,624
TOTAL ASSETS	$5,065,225	$4,977,011

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	721,120	719,899
Retained Earnings	444,259	408,718
Accumulated Other Comprehensive Income (Loss)	(56,550)	(52,088)
Total Common Shareholder's Equity	1,369,287	1,336,987
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholder's Equity	1,387,071	1,354,771
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,360	5,360
Long-term Debt	1,128,920	1,703,073
TOTAL	2,521,351	3,063,204
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	651,008	161,008
Advances from Affiliates	151,558	82,994
Accounts Payable:		
General	120,705	140,497
Affiliated Companies	65,734	81,812
Customer Deposits	45,552	33,930
Taxes Accrued	77,933	50,259
Interest Accrued	22,149	22,113
Risk Management Liabilities	83,792	51,430
Obligations Under Capital Leases	7,074	9,218
Other	54,460	60,289
TOTAL	1,279,965	693,550
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	823,671	803,355
Regulatory Liabilities:		
Asset Removal Costs	95,206	92,497
Deferred Investment Tax Credits	32,635	30,545
Over Recovery of Fuel Cost	69,312	68,704
Other Regulatory Liabilities	23,493	17,326
Long-term Risk Management Liabilities	67,789	54,327
Obligations Under Capital Leases	13,935	16,134
Asset Retirement Obligation	22,635	21,776
Deferred Credits and Other	115,233	115,593
TOTAL	1,263,909	1,220,257
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,065,225	$4,977,011

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$87,162	$171,046
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(77,257)
Depreciation and Amortization	95,144	82,073
Deferred Income Taxes	24,377	2,305
Deferred Investment Tax Credits	2,090	(847)
Deferred Property Taxes	5,793	5,343
Deferred Power Supply Costs, Net	607	69,528
Mark to Market of Risk Management Contracts	5,615	19,433
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	29,423	64,565
Fuel, Materials and Supplies	(33,738)	2,965
Accounts Payable	(35,870)	(79,628)
Taxes Accrued	27,674	33,303
Interest Accrued	36	2,255
Incentive Plan Accrued	(1,940)	(9,388)
Rate Stabilization Deferral	-	(75,601)
Change in Other Assets	9,952	3,483
Change in Other Liabilities	12,617	53,805
Net Cash Flows From Operating Activities	228,942	267,383
INVESTING ACTIVITIES		
Construction Expenditures	(204,225)	(114,806)
Proceeds from Sale of Property and Other	579	1,648
Change in Other Cash Deposits, Net	40,615	(12)
Net Cash Flows Used For Investing Activities	(163,031)	(113,170)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	-	495,122
Retirement of Long-term Debt	(85,005)	(420,238)
Change in Advances from Affiliates, Net	68,564	(157,870)
Dividends Paid on Common Stock	(50,000)	(64,133)
Dividends Paid on Cumulative Preferred Stock	(400)	(721)
Net Cash Flows Used For Financing Activities	(66,841)	(147,840)
Net Increase (Decrease) in Cash and Cash Equivalents	(930)	6,373
Cash and Cash Equivalents at Beginning of Period	4,561	4,133
Cash and Cash Equivalents at End of Period	$3,631	$10,506

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $46,739,000 and $56,152,000 and for income taxes was $3,946,000 and $21,102,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to APCo. The footnotes begin on page L-1.

Results of Operations

The increase in Net Income of $1 million in second quarter 2004 was primarily due to a $25 million increase in operating revenue, partially offset by a $9 million increase in fuel expense and a combined $15 million increase in other operating expenses.

The decrease in year-to-date Net Income of $19 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 $7 million increase in fuel expense, combined increases of $20 million in other operating expenses and a $5 million increase in Nonoperating Income Tax Expense, which was partially offset by increases of $28 million in operating revenues and $14 million in nonoperating risk management activities.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income increased $1 million primarily due to:

o An increase of $21 million in retail electric revenues resulting from increased weather-related demand from residential and commercial customers and an increase in customer base.
o An increase of $10 million in operating revenues related to favorable results from risk management activities.

The increase in Operating Income was partially offset by:

o A decrease of $7 million in non-affiliated wholesale energy sales due to lower sales volume and the expiration of municipal contracts.
o An increase of $9 million in fuel expense due to increased electric generation and higher fuel costs per KWH.
o An increase of $7 million in Other Operation expense primarily relating to uncollectible accounts, pension plan costs and increased allocated costs from AEPSC.
o An increase of $3 million in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages and increased overhead distribution line expenses.
o An increase of $3 million in Depreciation and Amortization expenses due to a greater depreciable base in 2004, including capital software costs allocated from AEPSC and the increased amortization of regulatory assets due to a federal tax adjustment to the asset account and quarterly adjustments to the amortization rate.
o An increase of $2 million in Taxes Other than Income Taxes due to increased state excise taxes.

Other Impacts on Earnings

Nonoperating Income Tax Expense decreased $1 million. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 33.6% and 34.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to the flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income increased $1 million primarily due to:

o An increase of $30 million in retail electric revenues resulting primarily from increased weather-related demand from residential and commercial customers during the second quarter 2004.
o An increase of $8 million in operating revenues related to favorable results from risk management activities.

The increase in Operating Income was partially offset by:

o A decrease of $9 million in non-affiliated wholesale energy sales due to lower sales volume and the expiration of municipal contracts.
o An increase of $7 million in Fuel for Electric Generation due to increased electric generation and higher fuel costs per KWH.
o An increase of $8 million in Other Operation expense primarily relating to uncollectible accounts, pension plan costs and increased

allocated costs from AEPSC.
o An increase of $6 million in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages and increased overhead and underground line expenses.
o An increase of $6 million in Depreciation and Amortization expenses due to a greater depreciable base in 2004, including capital software costs allocated from AEPSC and the increased amortization of regulatory assets due to a federal tax adjustment to the asset account and quarterly adjustment to the amortization rate.

Other Impacts on Earnings

Nonoperating Income increased $12 million primarily due to favorable results from risk management activities.

Nonoperating Income Tax Expense increased $5 million. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 35.1% and 34.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to the flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

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

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

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$43,695	Variable	2038

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$11,000	7.60	2024
Installment Purchase Contracts	43,695	6.25	2020

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(13,471)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	369
Change in Fair Value Due to Valuation Methodology Changes (d)	898
Changes in Fair Value of Risk Management Contracts (e)	9,080
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	35,213
Net Cash Flow Hedge Contracts (g)	(3,375)
DETM Assignment (h)	(16,673)
Total MTM Risk Management Contract Net Assets at June 30, 2004	$15,165

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See Note 17 "Related Party Transactions" 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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(2,241)	$223	$(6)	$711	$-	$-	$(1,313)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	10,050	3,220	2,256	1,216	570	-	17,312
Prices Based on Models and Other Valuation Methods (b)	175	3,644	1,693	2,974	3,020	7,708	19,214
Total	$7,984	$7,087	$3,943	$4,901	$3,590	$7,708	$35,213

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Six Months Ended June 30, 2004

	Power
	(in thousands)
Beginning Balance December 31, 2003	$202
Changes in Fair Value (a)	(1,796)
Reclassifications from AOCI to Net Income (b)	(601)
Ending Balance June 30, 2004	$(2,195)

(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 $1,404 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$575	$1,304	$649	$325	$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 $85 million and $98 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$336,793	$313,359	$680,479	$651,796
Sales to AEP Affiliates	21,333	19,712	39,952	40,480
TOTAL	358,126	333,071	720,431	692,276
OPERATING EXPENSES				
Fuel for Electric Generation	51,159	37,924	92,796	85,464
Fuel From Affiliates for Electric Generation	1,755	6,100	10,603	10,603
Purchased Electricity for Resale	4,769	4,012	9,450	8,210
Purchased Electricity from AEP Affiliates	85,706	87,590	167,421	169,739
Other Operation	58,796	52,294	116,277	108,679
Maintenance	25,944	22,612	42,770	37,171
Depreciation and Amortization	36,445	33,299	73,263	67,036
Taxes Other Than Income Taxes	32,726	30,954	68,052	66,562
Income Taxes	16,197	14,869	40,662	40,244
TOTAL	313,497	289,654	621,294	593,708
OPERATING INCOME	44,629	43,417	99,137	98,568
Nonoperating Income (Loss)	770	311	5,848	(6,365)
Nonoperating Expenses	859	584	1,593	2,785
Nonoperating Income Tax Expense (Credit)	(628)	400	291	(5,147)
Interest Charges	14,413	13,413	27,227	26,875
Income Before Cumulative Effect of Accounting Changes	30,755	29,331	75,874	67,690
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	27,283
NET INCOME	30,755	29,331	75,874	94,973
Preferred Stock - Capital Stock Expense	254	254	508	508
EARNINGS APPLICABLE TO COMMON STOCK	$30,501	$29,077	$75,366	$94,465

The common stock of CSPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(86,622)		(86,622)
Capital Stock Expense		508	(508)		-
TOTAL					761,042
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,193)	(1,193)
NET INCOME			94,973		94,973
TOTAL COMPREHENSIVE INCOME					93,780
JUNE 30, 2003	$41,026	$575,892	$298,454	$(60,550)	$854,822
DECEMBER 31, 2003	$41,026	$576,400	$326,782	$(46,327)	$897,881
Common Stock Dividends Declared			(62,500)		(62,500)
Capital Stock Expense		508	(508)		-
TOTAL					835,381
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,397)	(2,397)
NET INCOME			75,874		75,874
TOTAL COMPREHENSIVE INCOME					73,477
JUNE 30, 2004	$41,026	$576,908	$339,648	$(48,724)	$908,858

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,645,647	$1,610,888
Transmission	429,803	425,512
Distribution	1,274,698	1,253,760
General	169,716	166,002
Construction Work in Progress	103,740	114,281
TOTAL	3,623,604	3,570,443
Accumulated Depreciation and Amortization	1,430,860	1,389,586
TOTAL - NET	2,192,744	2,180,857
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	21,771	22,417
Other Investments	6,889	8,663
TOTAL	28,660	31,080
CURRENT ASSETS		
Cash and Cash Equivalents	2,943	3,377
Other Cash Deposits	747	765
Accounts Receivable:		
Customers	43,660	47,099
Affiliated Companies	54,861	68,168
Accrued Unbilled Revenues	19,388	23,723
Miscellaneous	6,533	5,257
Allowance for Uncollectible Accounts	(1,209)	(531)
Fuel	26,019	14,365
Materials and Supplies	66,754	44,377
Risk Management Assets	55,556	40,095
Margin Deposits	2,500	6,636
Prepayments and Other	12,681	12,444
TOTAL	290,433	265,775
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Assets, Net	16,209	16,027
Transition Regulatory Assets	172,780	188,532
Unamortized Loss on Reacquired Debt	13,538	13,659
Other	22,477	24,966
Long-term Risk Management Assets	51,328	39,932
Deferred Property Taxes	31,499	62,262
Deferred Charges	17,644	15,276
TOTAL	325,475	360,654
TOTAL ASSETS	$2,837,312	$2,838,366

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	576,908	576,400
Retained Earnings	339,648	326,782
Accumulated Other Comprehensive Income (Loss)	(48,724)	(46,327)
Total Common Shareholder's Equity	908,858	897,881
Long-term Debt	838,654	886,564
TOTAL	1,747,512	1,784,445
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	48,550	11,000
Advances from Affiliates, Net	5,959	6,517
Accounts Payable:		
General	51,619	58,220
Affiliated Companies	40,089	53,572
Customer Deposits	26,472	19,727
Taxes Accrued	114,063	132,853
Interest Accrued	16,533	16,528
Risk Management Liabilities	50,829	28,966
Obligations Under Capital Leases	3,834	4,221
Other	22,858	25,364
TOTAL	380,806	356,968
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	466,032	458,498
Regulatory Liabilities:		
Asset Removal Costs	101,441	99,119
Deferred Investment Tax Credits	29,324	30,797
Long-term Risk Management Liabilities	40,890	30,598
Obligations Under Capital Leases	9,672	11,397
Asset Retirement Obligations	9,085	8,740
Deferred Credits and Other	52,550	57,804
TOTAL	708,994	696,953
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,837,312	$2,838,366

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$75,874	$94,973
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(27,283)
Depreciation and Amortization	73,263	67,036
Deferred Income Taxes	8,642	(3,135)
Deferred Investment Tax Credits	(1,473)	(1,526)
Deferred Property Taxes	31,039	30,973
Mark-to-Market of Risk Management Contracts	1,611	19,215
Gain on Sale of Assets	(1,786)	-
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	20,483	34,337
Fuel, Materials and Supplies	(34,031)	1,005
Accounts Payable	(20,084)	(39,326)
Taxes Accrued	(18,790)	(24,796)
Interest Accrued	5	7,669
Change in Other Assets	3,976	(9,835)
Change in Other Liabilities	360	502
Net Cash Flows From Operating Activities	139,089	149,809
INVESTING ACTIVITIES		
Construction Expenditures	(67,148)	(65,492)
Proceeds from Sale of Property and Other	2,265	190
Change in Other Cash Deposits, Net	18	(6)
Net Cash Flows Used For Investing Activities	(64,865)	(65,308)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	43,095	494,350
Change in Advances to/from Affiliates, Net	(558)	146,271
Retirement of Long-term Debt - Nonaffiliated	(54,695)	(182,500)
Retirement of Long-term Debt - Affiliated	-	(160,000)
Change in Short-term Debt - Affiliates	-	(290,000)
Dividends Paid on Common Stock	(62,500)	(86,622)
Net Cash Flows Used For Financing Activities	(74,658)	(78,501)
Net Increase (Decrease) in Cash and Cash Equivalents	(434)	6,000
Cash and Cash Equivalents at Beginning of Period	3,377	697
Cash and Cash Equivalents at End of Period	$2,943	$6,697

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $25,131,000 and $18,442,000 and for income taxes was $(3,747,000) and $(9,245,000) in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to CSPCo. The footnotes begin on page L-1.

Results of Operations

Net Income increased $28 million for the second quarter of 2004 and $44 million for the first six months of 2004. The increases in Net Income reflect improvement in retail sales, the end of amortization of Cook Plant outage settlements and reduced financing charges in both the quarter and year-to-date periods and favorable results from risk management activities for the year-to-date period.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income increased $24 million primarily due to:

o An $18 million increase in retail revenues due primarily to a weather-related increase in residential and commercial sales, an improvement in industrial sales reflecting the recovering economy and the end of amortization of Cook outage settlements.
o A $6 million increase in wholesale sales, including favorable results from risk management activities.
o The increased availability of the Cook Plant that resulted in a $5 million increase in Sales to Affiliates and an $8 million decrease in Purchased Electricity from AEP affiliates.

The increase in Operating Income was partially offset by:

o A $4 million increase in Maintenance expense due primarily to the cost of a forced outage at Rockport Plant Unit 2, a planned outage at Tanner's Creek Plant Unit 1 and storm damage expenses in May and June of 2004.
o A $3 million increase in Taxes Other Than Income Taxes primarily due to favorable property tax adjustments that were recorded in 2003.
o A $9 million increase in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income increased $4 million due to favorable results from risk management activities and increased barging revenues from nonaffiliated companies.

Nonoperating Expenses increased $2 million mainly due to increased expenses related to increased barging revenues from nonaffiliated companies.

Nonoperating Income Taxes increased $2 million. See Income Taxes section below for further discussion.

Interest Charges decreased $4 million primarily due to a reduction in outstanding long-term debt and due to lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 36.7% and 135.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The change in the effective tax rate is primarily due to lower pre-tax income in 2003 offsetting the effect of flow-through and permanent differences, and state income taxes.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income increased $22 million primarily due to:

o A $27 million increase in Electric Generation, Transmission and Distribution revenues due to an increase in residential and commercial sales reflecting warmer spring weather in 2004, an improvement in industrial sales reflecting an improvement in the economy and the end of amortization of Cook Plant outage settlements.
o A $9 million decrease in Fuel for Electric Generation expense reflecting a change in fuel mix as nuclear generation increased 48% and coal-fired generation declined 18% due to generating unit availability.
o A $10 million decrease in Purchased Electricity from AEP Affiliates primarily due to a 10% increase in net generation.
o A decrease of $4 million in Other Operation expense which included the end of amortization of Cook Plant outage settlements.

The increase in Operating Income was partially offset by:

o A $7 million decrease in Sales to AEP Affiliates due to lower capacity revenues.
o A $10 million increase in Maintenance expense due primarily to both planned and forced outages at Rockport Plant Unit 2, a planned outage at Tanner's Creek Plant Unit 1 and increased cost of storm damage in May and June of 2004.
o A $2 million increase in Taxes Other Than Income Taxes primarily due to favorable property tax adjustments recorded in 2003 offset by decreased Federal Insurance Contributions Act tax reflecting a reduction in employees from the sustained earnings improvement initiative and timing of payroll accrual.
o A $13 million increase in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income increased $19 million primarily due to favorable results from risk management activities.

Nonoperating Income Tax increased $8 million. See Income Taxes section below for further discussion.

Interest Charges decreased $9 million primarily due to a reduction in outstanding long-term debt and due to lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 37.3% and 41.8%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pre-tax income in 2003 offsetting the effect of flow-through and permanent differences, and state income taxes.

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 six months of 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$3,899	$3,251

Cash flow from (used for):		
Operating activities	260,645	88,838
Investing activities	(78,054)	(70,850)
Financing activities	(183,319)	(15,513)
Net increase (decrease) in cash and cash equivalents	(728)	2,475
Cash and cash equivalents at end of period	$3,171	$5,726

Operating Activities

Operating activities during 2004 provided $172 million more cash than during 2003 largely due to increased net income of $44 million and improved working capital requirements.

Investing Activities

Cash Flows Used For Investing Activities during 2004 were $7 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 $168 million more cash from operations than during 2003 primarily to reduce short-term debt outstanding and pay common dividends.

Financing Activity

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

Issuances

None.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$30,000	7.20	2024
First Mortgage Bonds	25,000	7.50	2024

Off-Balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. 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 policy restricts 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.

Spent Nuclear Fuel Disposal

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for spent nuclear fuel (SNF), we and South Texas Project Nuclear Operating Company, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability. The case continued on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages, which we intend to appeal. As long as the delay in the availability of the government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase. If such cost increases are not recovered on a timely basis in regulated rates, future results of operations and cash flows could be adversely affected.

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(13,076)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	404
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	1,913
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	7,641
Total MTM Risk Management Contract Net Assets	38,877
Net Cash Flow Hedge Contracts (f)	(4,394)
DETM Assignment (g)	(18,276)

Total MTM Risk Management Contract Net Assets at June 30, 2004	$16,207

(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 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).
(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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(2,456)	$244	$(7)	$779	$-	$-	$(1,440)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,338	3,530	2,472	1,333	625	-	19,298
Prices Based on Models and Other Valuation Methods (b)	150	3,994	1,856	3,260	3,310	8,449	21,019
Total	$9,032	$7,768	$4,321	$5,372	$3,935	$8,449	$38,877

(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, economic hedge contracts which are not designated as cash flow hedges are required to be market-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2004

	Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$222	$-	$222
Changes in Fair Value (a)	(1,968)	(351)	(2,319)
Reclassifications from AOCI to Net Income (b)	(659)	-	(659)
Ending Balance June 30, 2004	$(2,405)	$(351)	$(2,756)

(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.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,557 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$630	$1,430	$711	$357	$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 $88 million and $79 million at June 30, 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 OPERATIONS
For the Three and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$339,874	$316,506	$693,272	$666,293
Sales to AEP Affiliates	65,025	60,400	122,670	129,211
TOTAL	404,899	376,906	815,942	795,504
OPERATING EXPENSES				
Fuel for Electric Generation	65,582	65,763	129,623	138,857
Purchased Electricity for Resale	6,191	7,035	12,554	13,317
Purchased Electricity from AEP Affiliates	65,665	73,353	128,793	139,251
Other Operation	105,224	108,532	205,650	209,913
Maintenance	46,276	42,595	84,318	73,962
Depreciation and Amortization	42,696	42,841	85,411	86,567
Taxes Other Than Income Taxes	15,472	12,149	30,688	28,970
Income Taxes	14,798	5,409	39,097	26,448
TOTAL	361,904	357,677	716,134	717,285
OPERATING INCOME	42,995	19,229	99,808	78,219
Nonoperating Income	20,021	15,673	40,609	21,947
Nonoperating Expenses	17,331	15,287	32,182	30,877
Nonoperating Income Tax Expense (Credit)	878	(849)	2,491	(5,300)
Interest Charges	17,777	21,655	35,706	45,093
Net Income (Loss) Before Cumulative Effect of Accounting Change	27,030	(1,191)	70,038	29,496
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	(3,160)
NET INCOME (LOSS)	27,030	(1,191)	70,038	26,336
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	119	1,123	237	2,272
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$26,911	$(2,314)	$69,801	$24,064

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(20,000)		(20,000)
Preferred Stock Dividends			(2,205)		(2,205)
Capital Stock Expense		67	(67)		-
					996,448
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,276)	(1,276)
NET INCOME			26,336		26,336
TOTAL COMPREHENSIVE INCOME					25,060
JUNE 30, 2003	$56,584	$858,627	$148,060	$(41,763)	$1,021,508
DECEMBER 31, 2003	$56,584	$858,694	$187,875	$(25,106)	$1,078,047
Common Stock Dividends			(59,293)		(59,293)
Preferred Stock Dividends			(169)		(169)
Capital Stock Expense		67	(67)		-
					1,018,585
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(2,978)	(2,978)
NET INCOME			70,038		70,038
TOTAL COMPREHENSIVE INCOME					67,060
JUNE 30, 2004	$56,584	$858,761	$198,384	$(28,084)	$1,085,645

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,915,508	$2,878,051
Transmission	1,003,939	1,000,926
Distribution	969,804	958,966
General (including nuclear fuel)	263,738	274,283
Construction Work in Progress	189,638	193,956
TOTAL	5,342,627	5,306,182
Accumulated Depreciation and Amortization	2,547,376	2,490,912
TOTAL - NET	2,795,251	2,815,270
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,013,050	982,394
Non-Utility Property, Net	50,824	52,303
Other Investments	31,608	43,797
TOTAL	1,095,482	1,078,494
CURRENT ASSETS		
Cash and Cash Equivalents	3,171	3,899
Other Cash Deposits	55	15
Accounts Receivable:		
Customers	56,158	63,084
Affiliated Companies	88,177	124,826
Miscellaneous	4,951	4,498
Allowance for Uncollectible Accounts	(91)	(531)
Fuel	34,959	33,968
Materials and Supplies	121,573	105,328
Risk Management Assets	61,545	44,071
Margin Deposits	2,728	7,245
Prepayments and Other	9,694	10,673
TOTAL	382,920	397,076
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	143,986	151,973
Incremental Nuclear Refueling Outage Expenses, Net	31,322	57,326
Other	74,049	66,978
Long-term Risk Management Assets	56,260	43,768
Deferred Property Taxes	20,896	21,916
Deferred Charges and Other Assets	31,487	26,270
TOTAL	358,000	368,231
TOTAL ASSETS	$4,631,653	$4,659,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	858,761	858,694
Retained Earnings	198,384	187,875
Accumulated Other Comprehensive Income (Loss)	(28,084)	(25,106)
Total Common Shareholder's Equity	1,085,645	1,078,047
Cumulative Preferred Stock - Not Subject to Mandatory Redemption	8,101	8,101
Total Shareholder's Equity	1,093,746	1,086,148
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	61,445	63,445
Long-term Debt	1,135,993	1,134,359
TOTAL	2,291,184	2,283,952
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	150,000	205,000
Advances from Affiliates	31,965	98,822
Accounts Payable:		
General	75,425	101,776
Affiliated Companies	41,730	47,484
Customer Deposits	30,866	21,955
Taxes Accrued	86,512	42,189
Interest Accrued	16,986	17,963
Risk Management Liabilities	56,297	31,898
Obligations Under Capital Leases	6,053	6,528
Other	60,988	57,675
TOTAL	556,822	631,290
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	326,660	337,376
Regulatory Liabilities:		
Asset Removal Costs	269,921	263,015
Deferred Investment Tax Credits	86,614	90,278
Excess ARO for Nuclear Decommissioning	228,743	215,715
Other	71,339	61,268
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	68,325	70,179
Long-term Risk Management Liabilities	45,301	33,537
Obligations Under Capital Leases	29,262	31,315
Asset Retirement Obligations	572,786	553,219
Deferred Credits and Other	84,696	87,927
TOTAL	1,783,647	1,743,829
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,631,653	$4,659,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$70,038	$26,336
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	3,160
Depreciation and Amortization	85,411	86,567
Deferred Income Taxes	(524)	(10,252)
Deferred Investment Tax Credits	(3,664)	(3,670)
Deferred Property Taxes	1,211	623
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	26,004	(8,799)
Unrecovered Fuel and Purchased Power Costs	1,171	18,751
Amortization of Nuclear Outage Costs	-	20,000
Mark-to-Market of Risk Management Contracts	1,461	19,474
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	42,682	73,530
Fuel, Materials and Supplies	(17,236)	1,599
Accounts Payable	(32,105)	(107,218)
Taxes Accrued	44,323	(19,201)
Change in Other Assets	12,014	(12,310)
Change in Other Liabilities	29,859	248
Net Cash Flows From Operating Activities	260,645	88,838
INVESTING ACTIVITIES		
Construction Expenditures	(78,014)	(71,246)
Other	-	415
Change in Other Cash Deposits, Net	(40)	(19)
Net Cash Flows Used For Investing Activities	(78,054)	(70,850)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(2,000)	(1,500)
Retirement of Long-term Debt - Nonaffiliated	(55,000)	(255,000)
Change in Advances to/from Affiliates, Net	(66,857)	263,192
Dividends Paid on Common Stock	(59,293)	(20,000)
Dividends Paid on Cumulative Preferred Stock	(169)	(2,205)
Net Cash Flows Used For Financing Activities	(183,319)	(15,513)
Net Increase (Decrease) in Cash and Cash Equivalents	(728)	2,475
Cash and Cash Equivalents at Beginning of Period	3,899	3,251
Cash and Cash Equivalents at End of Period	$3,171	$5,726

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $34,825,000 and $44,812,000 and for income taxes was $189,000 and $50,731,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's consolidated financial statements are combined with the notes to financial statements for other 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

Net Income for the second quarter of 2004 was relatively flat compared to the prior year period as increased retail revenues were essentially offset by increased Maintenance expenses.

Net Income for the six months ended June 30, 2004 was up $2 million over 2003 primarily due to favorable results on risk management activities, partially offset by the Cumulative Effect of Accounting Change recorded in 2003.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income for the second quarter of 2004 was up slightly over the prior year period. The positive factors contributing to the change in Operating Income for 2004 were:

o A $10 million increase in Electric Generation, Transmission and Distribution revenues due to increased retail revenues due primarily to a weather related increase in residential and commercial sales, an improvement in industrial sales reflecting the recovering economy and the rate increase in mid-2003 to recover the cost of emission control equipment.
o A 32% increase in the Big Sandy Plant's generation which led to a decline in Purchases from AEP Affiliates of $4 million. The increase in generation was due to planned plant outages in 2003 for the implementation of emission control equipment.
o A $2 million decrease in Income Taxes (see "Income Taxes" below).

These increases in Operating Income were partially offset by:

o An increase in Fuel for Electric Generation expense of $10 million resulting from a 32% increase in generation over the second quarter of 2003 and an increase in the average cost per ton of fuel consumed.
o An increase of $3 million in Maintenance expense related to planned outages for boiler overhauls in the second quarter of 2004 and storm damages in the second quarter of 2004.
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 An increase in Other Operation expense of $1 million due to increased allocated costs from AEPSC.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $1 million in the first quarter of 2004 compared to 2003 primarily due to favorable results from risk management activities.

Interest Charges increased approximately $577 thousand primarily due to increased long-term debt outstanding.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 21.7% and 30.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes offset by flow-through property-related differences.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income for 2004 was virtually unchanged from 2003. Items that favorably impacted operating income were:

o A $13 million increase in Electric Generation, Transmission and Distribution revenues due to increased retail revenues primarily related to the rate increase in mid-2003 to recover the cost of emission control equipment.
o A decrease in Purchased Electricity from AEP Affiliates of $8 million resulting from a 30% increase in Big Sandy's generation in 2004. The increase in generation was due to planned plant outages in 2003 for the implementation of emission control equipment.
o A $2 million decrease in Income Taxes (see "Income Taxes" below).

These increases in Operating Income were partially offset by:

o An increase in Fuel for Electric Generation expense of $13 million resulting from a 30% increase in generation over 2003 and an increase in the average cost per ton of fuel consumed.
o An increase in Other Operation expense of $2 million due to increased allocated costs from AEPSC.
o An increase of $4 million in Maintenance expense related to planned outages for boiler overhauls in 2004.
o An increase in Depreciation and Amortization of $4 million in 2004 due to the implementation of emission control equipment at the Big Sandy plant in mid-2003.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $5 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Interest Charges increased $1 million primarily due to increased long-term debt outstanding.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 32.2% and 35.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes.

Financial Condition

Credit Ratings

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

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

Financing Activity

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

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(4,712)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	142
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	406
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (e)	2,119
Total MTM Risk Management Contract Net Assets	13,445
Net Cash Flow Hedge Contracts (f)	(1,097)
DETM Assignment (g)	(6,366)
Total MTM Risk Management Contract Net Assets at June 30, 2004	$5,982

(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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(855)	$85	$(2)	$271	$-	$-	$(501)
Prices Provided by Other External							

Sources - OTC Broker Quotes (a)	3,837	1,230	862	464	218	-	6,611
Prices Based on Models and Other Valuation Methods (b)	67	1,391	646	1,135	1,153	2,943	7,335
Total	$3,049	$2,706	$1,506	$1,870	$1,371	$2,943	$13,445

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2004

	Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$82	$338	$420
Changes in Fair Value (a)	(693)	-	(693)
Reclassifications from AOCI to Net Income (b)	(226)	(43)	(269)
Ending Balance June 30, 2004	$(837)	$295	$(542)

(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 $450 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$220	$498	$248	$124	$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 $25 million and $29 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended 2004	Three Months Ended 2003	Six Months Ended 2004	Six Months Ended 2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$94,034	$84,296	$200,935	$188,255
Sales to AEP Affiliates	12,373	11,168	18,985	19,303
TOTAL	106,407	95,464	219,920	207,558
OPERATING EXPENSES				
Fuel for Electric Generation	25,224	15,439	46,118	33,386
Purchased Electricity from AEP Affiliates	31,817	36,152	65,123	73,547
Other Operation	13,153	11,695	26,280	23,832
Maintenance	10,214	7,161	17,539	13,926
Depreciation and Amortization	10,905	9,248	21,764	17,960
Taxes Other Than Income Taxes	2,395	2,077	4,723	4,442
Income Taxes	1,094	2,728	7,554	9,667
TOTAL	94,802	84,500	189,101	176,760
OPERATING INCOME	11,605	10,964	30,819	30,798
Nonoperating Income (Loss)	674	(547)	1,626	(2,945)
Nonoperating Expenses	466	113	1,779	362
Nonoperating Income Tax Expense (Credit)	33	(926)	(94)	(1,484)
Interest Charges	7,712	7,135	15,081	13,859
Income Before Cumulative Effect of Accounting Change	4,068	4,095	15,679	15,116
Cumulative Effect of Accounting Change (Net of Tax)	-	-	-	(1,134)
NET INCOME	$4,068	$4,095	$15,679	$13,982

The common stock of KPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(10,966)		(10,966)
TOTAL					287,052
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(506)	(506)
NET INCOME			13,982		13,982
TOTAL COMPREHENSIVE INCOME					13,476
JUNE 30, 2003	$50,450	$208,750	$51,285	$(9,957)	$300,528
DECEMBER 31, 2003	$50,450	$208,750	$64,151	$(6,213)	$317,138
Common Stock Dividends			(12,500)		(12,500)
TOTAL					304,638
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(962)	(962)
NET INCOME			15,679		15,679
TOTAL COMPREHENSIVE INCOME					14,717
JUNE 30, 2004	$50,450	$208,750	$67,330	$(7,175)	$319,355

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$460,577	$457,341
Transmission	383,329	381,354
Distribution	433,655	425,688
General	59,248	68,041
Construction Work in Progress	12,507	17,322
TOTAL	1,349,316	1,349,746
Accumulated Depreciation and Amortization	385,237	381,876
TOTAL - NET	964,079	967,870
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	5,442	5,423
Other Investments	398	1,022
TOTAL	5,840	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	695	863
Other Cash Deposits	17	23
Advances to Affiliates	3,522	-
Accounts Receivable:		
Customers	21,279	21,177
Affiliated Companies	21,631	25,327
Accrued Unbilled Revenues	4,501	5,534
Miscellaneous	283	97
Allowance for Uncollectible Accounts	(69)	(736)
Fuel	11,309	9,481
Materials and Supplies	19,911	16,585
Risk Management Assets	21,211	16,200
Margin Deposits	961	2,660
Prepayments and Other	1,601	1,696
TOTAL	106,852	98,907
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	102,853	99,828
Other Regulatory Assets	15,147	13,971
Long-term Risk Management Assets	20,995	16,134
Deferred Property Taxes	3,511	6,847
Other Deferred Charges	11,515	11,632
TOTAL	154,021	148,412
TOTAL ASSETS	$1,230,792	$1,221,634

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPATALIZATION AND LIABILITIES
June 30, 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	67,330	64,151
Accumulated Other Comprehensive Income (Loss)	(7,175)	(6,213)
Total Common Shareholder's Equity	319,355	317,138
Long-term Debt:		
Nonaffiliated	427,841	427,602
Affiliated	80,000	60,000
Total Long-term Debt	507,841	487,602
TOTAL	827,196	804,740
CURRENT LIABILITIES		
Advances from Affiliates	-	38,096
Accounts Payable:		
General	22,366	22,802
Affiliated Companies	19,928	22,648
Customer Deposits	12,671	9,894
Taxes Accrued	10,999	7,329
Interest Accrued	6,783	6,915
Risk Management Liabilities	20,613	11,704
Obligations Under Capital Leases	1,653	1,743
Other	7,979	8,628
TOTAL	102,992	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	219,244	212,121
Regulatory Liabilities:		
Asset Removal Costs	28,492	26,140
Deferred Investment Tax Credits	7,370	7,955
Other Regulatory Liabilities	13,167	10,591
Long-term Risk Management Liabilities	15,611	12,363
Obligations Under Capital Leases	3,077	3,549
Deferred Credits and Other	13,643	14,416
TOTAL	300,604	287,135
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,230,792	$1,221,634

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$15,679	$13,982
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Change	-	1,134
Depreciation and Amortization	21,764	17,960
Deferred Income Taxes	4,616	7,605
Deferred Investment Tax Credits	(585)	(587)
Deferred Property Taxes	3,424	3,150
Deferred Fuel Costs, Net	(1,514)	(932)
Loss on Sale of Assets	1,051	-
Mark-to-Market of Risk Management Contracts	1,064	6,697
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	3,774	12,065
Fuel, Materials and Supplies	(5,154)	(2,672)
Accounts Payable	(3,156)	(43,251)
Taxes Accrued	3,670	6,175
Change in Other Assets	(4,165)	(4,773)
Change in Other Liabilities	10,013	1,261
Net Cash Flows From Operating Activities	50,481	17,814
INVESTING ACTIVITIES		
Construction Expenditures	(18,075)	(57,897)
Proceeds from Sales of Property and Other	1,538	298
Change in Other Cash Deposits, Net	6	(1)
Net Cash Flow Used for Investing Activities	(16,531)	(57,600)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Affiliated	20,000	74,263
Retirement of Long-term Debt - Nonaffiliated	-	(40,000)
Retirement of Long-term Debt - Affiliated	-	(15,000)
Change in Advances to/from Affiliates, Net	(41,618)	30,876
Dividends Paid	(12,500)	(10,966)
Net Cash Flows From (Used For) Financing Activities	(34,118)	39,173
Net Decrease in Cash and Cash Equivalents	(168)	(613)
Cash and Cash Equivalents at Beginning of Period	863	2,285
Cash and Cash Equivalents at End of Period	$695	$1,672

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $14,625,000 and $13,245,000 and for income taxes was $658,000 and $(5,537,000) in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

KENTUCKY POWER COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCo's financial statements are combined with the notes to financial statements for other 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 $17 million for the quarter due primarily to a $16 million decrease in Sales to AEP Affiliates. Net Income decreased $130 million year-to-date primarily due to a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003. Income Before Cumulative Effect of Accounting Changes decreased $6 million year-to-date primarily due to a decrease in Sales to AEP affiliates.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income decreased $17 million for the three months ended June 30, 2004 compared with the three months ended June 30, 2003 due to:

o A $16 million decrease in Sales to AEP Affiliates. The decrease is primarily the result of a 29% decrease in MWH for affiliated system sales partially offset by an increase in price per MWH. The decrease in MWH was primarily a result of an increase in planned boiler overhauls.
o A $13 million decrease in non-affiliated wholesale energy sales due to lower sales volumes.
o A $10 million increase in Other Operation expense primarily due to a $7 million pre-tax adjustment in 2003 to the workers' compensation reserve related to the sale of coal companies coupled with an increase in allocated costs from AEPSC.
o A $10 million increase in Depreciation and Amortization expense 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 the corresponding amortization amount.

The decrease in Operating Income was partially offset by:

o A $10 million increase in retail electric revenues resulting from increased weather-related demand from residential and commercial customers and increased usage from industrial customers. Cooling degree days increased 59% for the three months ended June 30, 2004 compared to three months ended June 30, 2003.
o A $15 million increase due to favorable results from risk management activities.
o An $8 million decrease in Fuel for Electric Generation due to decreased net generation as a result of an increase in planned boiler overhauls.

Other Impacts of Earnings

Nonoperating Income increased $48 million primarily due to sales of excess energy purchased from Dow at the Plaquemine, Louisiana plant (discussed in Note
5) including the effects of a related affiliate agreement which eliminates OPCo's market exposure related to the purchases from Dow. There was no change in overall Net Income due to the agreement with Dow.

Nonoperating Expense increased $42 million primarily due to the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (discussed in Note 5). There was no change in overall Net Income due to the agreement with Dow.

Interest Charges increased $11 million due primarily to the consolidation of JMG and its associated debt along with issuance of additional long-term debt subsequent to second quarter 2003. (There was no change in overall Net Income due to the consolidation of JMG).

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 33.0% and 33.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income decreased $7 million for the six months ended June 30, 2004 compared with the six months ended June 30, 2003 due to:

o A $20 million decrease in non-affiliated wholesale energy sales due to a lower sales volume.
o A $9 million decrease in Sales to AEP Affiliates. The decrease is primarily the result of a 7.5% decrease in MWH for affiliated system sales.
o A $5 million increase in Fuel for Electric Generation due to higher pricing per MWH.
o A $7 million increase in Other Operation expense primarily due to a pre-tax adjustment in 2003 to the workers' compensation reserve related to the sale of coal companies.
o A $20 million increase in Depreciation and Amortization expense primarily associated with the OPCo consolidation of JMG. Depreciation expense related to the assets owned by JMG are consolidated with OPCo effective July 1, 2003 (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 and the increased amortization of regulatory assets due to a federal tax adjustment which increased the regulatory asset amount and the corresponding amortization amount.

The decrease in Operating Income was partially offset by:

o A $17 million increase in retail electric revenues resulting from increased weather-related demand from residential and commercial customers and increased usage from industrial customers. Cooling degree days increased 59% for the six months ended June 30, 2004 compared to the six months ended June 30, 2003.
o A $9 million increase due to favorable results from risk management activities.
o An $11 million decrease in Purchased Electricity for Resale 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 related to Ohio Valley Electric surplus charges was included in rates through April 30, 2003, no longer in effect for 2004.
o A $23 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts of Earnings

Nonoperating Income increased $68 million primarily due to sales of excess energy purchased from Dow at the Plaquemine, Louisiana plant (discussed in Note
5) including the effects of a related affiliate agreement which eliminates OPCo's market exposure related to the purchases from Dow. There was no change in overall Net Income due to the agreement with Dow. In addition, in the first six months of 2004 results from risk management activities were favorable compared to losses that were incurred in the first six months of 2003.

Nonoperating Expense increased $38 million primarily due to the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (discussed in Note 5). There was no change in overall Net Income due to the agreement with Dow.

Interest Charges increased $23 million due primarily to the consolidation of JMG and its associated debt along with issuance of additional long-term debt subsequent to second quarter 2003. (There was no change in overall Net Income due to the consolidation of JMG).

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 35.0% and 39.7%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to the flow-through of book versus tax differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state income taxes.

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 six months ended June 30, 2004 and 2003 were as follows:

	2004	2003
	(in thousands)	
Cash and cash equivalents at beginning of period	$7,233	$5,275
Cash flows from (used for):		
Operating activities	300,773	80,467
Investing activities	(81,909)	(114,485)
Financing activities	(219,703)	37,408
Net increase (decrease) in cash and cash equivalents	(839)	3,390
Cash and cash equivalents at end of period	$6,394	$8,665

Operating Activities

Cash Flows From Operating Activities for the first six months of 2004 increased $220 million compared to the first six months of 2003. This is primarily due to significant reductions in Accounts Payable balances during the second quarter of 2003 partially associated with a wind-down of risk management activities in that year.

Investing Activities

Cash Flows Used For Investing Activities decreased by $33 million during the first six months of 2004 compared with the first six months of 2003 due primarily to the Change in Other Cash Deposits, Net primarily as a result of monies set aside in 2003 for the retirement of Installment Purchase Contracts in 2004.

Financing Activities

Cash Flows For Financing Activities used $220 million in the first six months of 2004 and provided $37 million in the first six months of 2003. This is primarily due to a decrease in the change in Advances to/from Affiliates, Net, during the first six months 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 six months of 2004 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Financing Obligations	$6,080	5.77	2024

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
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	2,927	6.81	2008
First Mortgage Bonds	10,000	7.30	2024

Other

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

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. 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. 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 OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo 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 OPCo's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) 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. Management believes the PPA is enforceable. The litigation is now in the discovery phase.

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 "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(18,460)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	489
Change in Fair Value Due to Valuation Methodology Changes (d)	1,189
Changes in Fair Value of Risk Management Contracts (e)	9,965
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	47,121
Net Cash Flow Hedge Contracts (g)	(4,615)
DETM Assignment (h)	(22,057)

Total MTM Risk Management Contracts Net Assets at June 30, 2004	$20,449

(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)"Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h)See Note 17 "Related Party Transactions" 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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(2,964)	$295	$(8)	$940	$-	$-	$(1,737)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	13,047	5,244	2,985	1,608	755	-	23,639
Prices Based on Models and Other Valuation Methods (b)	199	4,653	2,240	3,935	3,995	10,197	25,219
Total	$10,282	$10,192	$5,217	$6,483	$4,750	$10,197	$47,121

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2004

	Power	Foreign Currency	Consolidated
		(in thousands)	
Beginning Balance December 31, 2003	$268	$(371)	$(103)
Changes in Fair Value (a)	(2,454)	-	(2,454)
Reclassifications from AOCI to Net Income (b)	(795)	7	(788)
Ending Balance June 30, 2004	$(2,981)	$(364)	$(3,345)

(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 $1,949 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$761	$1,725	$858	$430	$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 $170 million and $214 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$397,645	$387,892	$840,863	$838,779
Sales to AEP Affiliates	135,413	151,494	281,901	291,238
TOTAL	533,058	539,386	1,122,764	1,130,017
OPERATING EXPENSES				
Fuel for Electric Generation	145,503	153,446	311,774	307,094
Purchased Electricity for Resale	14,155	17,453	26,338	36,845
Purchased Electricity from AEP Affiliates	23,169	24,429	42,472	47,212
Other Operation	94,334	84,641	184,919	177,622
Maintenance	56,733	53,411	90,784	88,868
Depreciation and Amortization	70,388	60,224	142,170	121,775
Taxes Other Than Income Taxes	43,646	39,613	90,836	86,768
Income Taxes	22,220	26,338	62,202	85,132
TOTAL	470,148	459,555	951,495	951,316
OPERATING INCOME	62,910	79,831	171,269	178,701
Nonoperating Income	52,882	4,823	69,812	2,099
Nonoperating Expenses	49,231	7,331	57,300	19,041
Nonoperating Income Tax Expense (Credit)	(3,120)	1,564	1,967	(3,092)
Interest Charges	30,898	19,482	62,867	40,224
Income Before Cumulative Effect of Accounting Changes	38,783	56,277	118,947	124,627
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	124,632
NET INCOME	38,783	56,277	118,947	249,259
Preferred Stock Dividend Requirements	183	315	366	629
EARNINGS APPLICABLE TO COMMON STOCK	$38,600	$55,962	$118,581	$248,630

The common stock of OPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(83,867)		(83,867)
Preferred Stock Dividends			(629)		(629)
TOTAL					1,148,618
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,576)	(1,576)
Minimum Pension Liability				5,624	5,624
NET INCOME			249,259		249,259
TOTAL COMPREHENSIVE INCOME					253,307
JUNE 30, 2003	$321,201	$462,483	$687,079	$(68,838)	$1,401,925
DECEMBER 31, 2003	$321,201	$462,484	$729,147	$(48,807)	$1,464,025
Common Stock Dividends			(114,115)		(114,115)
Preferred Stock Dividends			(366)		(366)
TOTAL					1,349,544
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(3,242)	(3,242)
Minimum Pension Liability				(3,942)	(3,942)
NET INCOME			118,947		118,947
TOTAL COMPREHENSIVE INCOME					111,763
JUNE 30, 2004	$321,201	$462,484	$733,613	$(55,991)	$1,461,307

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$4,077,693	$4,029,515
Transmission	961,560	938,805
Distribution	1,178,394	1,156,886
General	251,549	245,434
Construction Work in Progress	158,402	160,675
Total	6,627,598	6,531,315
Accumulated Depreciation and Amortization	2,548,729	2,485,947
TOTAL - NET	4,078,869	4,045,368
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	29,463	29,291
Other	20,215	24,264
TOTAL	49,678	53,555
CURRENT ASSETS		
Cash and Cash Equivalents	6,394	7,233
Other Cash Deposits	65	51,017
Advances to Affiliates	168,140	67,918
Accounts Receivable:		
Customers	109,095	100,960
Affiliated Companies	121,263	120,532
Accrued Unbilled Revenues	9,063	17,221
Miscellaneous	1,198	736
Allowance for Uncollectible Accounts	(343)	(789)
Fuel	90,009	77,725
Materials and Supplies	98,955	92,136
Risk Management Assets	78,637	56,265
Margin Deposits	3,849	9,296
Prepayments and Other	13,025	15,883
TOTAL	699,350	616,133
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	170,684	169,605
Transition Regulatory Assets	267,673	310,035
Unamortized Loss on Reacquired Debt	11,405	10,172
Other	23,450	22,506
Long-term Risk Management Assets	71,411	52,825
Deferred Property Taxes	36,677	67,469
Deferred Charges and Other Assets	38,112	26,850
TOTAL	619,412	659,462
TOTAL ASSETS	$5,447,309	$5,374,518

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	733,613	729,147
Accumulated Other Comprehensive Income (Loss)	(55,991)	(48,807)
Total Common Shareholder's Equity	1,461,307	1,464,025
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,644	16,645
Total Shareholder's Equity	1,477,951	1,480,670
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	7,250
Long-term Debt:		
Nonaffiliated	1,610,480	1,608,086
Affiliated	200,000	-
Total Long-term Debt	1,810,480	1,608,086
TOTAL	3,293,431	3,096,006
Minority Interest	15,187	16,314
CURRENT LIABILITIES		
Short-term Debt - General	21,539	25,941
Long-term Debt Due Within One Year - Nonaffiliated	233,857	431,854
Accounts Payable:		
General	124,813	104,874
Affiliated Companies	83,459	101,758
Customer Deposits	28,099	17,308
Taxes Accrued	153,485	132,793
Interest Accrued	45,320	45,679
Risk Management Liabilities	72,462	38,318
Obligations Under Capital Leases	8,847	9,624
Other	66,525	71,642
TOTAL	838,406	979,791
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	935,192	933,582
Regulatory Liabilities:		
Asset Removal Costs	104,409	101,160
Deferred Investment Tax Credits	14,118	15,641
Other	-	3
Long-term Risk Management Liabilities	57,137	40,477
Deferred Credits	24,459	23,222
Obligations Under Capital Leases	21,826	25,064
Asset Retirement Obligations	44,338	42,656
Other	98,806	100,602
TOTAL	1,300,285	1,282,407
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,447,309	$5,374,518

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$118,947	$249,259
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(124,632)
Depreciation and Amortization	142,170	121,775
Deferred Income Taxes	4,400	372
Deferred Investment Tax Credits	(1,523)	(1,525)
Deferred Property Taxes	31,099	29,337
Mark-to-Market of Risk Management Contracts	4,819	26,381
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(1,616)	4,259
Fuel, Materials and Supplies	(19,103)	(2,519)
Prepayments and Other	8,305	(20,542)
Accounts Payable	1,640	(153,474)
Customer Deposits	10,791	9,524
Taxes Accrued	20,692	16,297
Interest Accrued	(359)	10,105
Change in Other Assets	(11,397)	(42,716)
Change in Other Liabilities	(8,092)	(41,434)
Net Cash Flows From Operating Activities	300,773	80,467
INVESTING ACTIVITIES		
Construction Expenditures	(134,001)	(117,761)
Change in Other Cash Deposits, Net	50,952	-
Proceeds from Sale of Property and Other	1,140	3,276
Net Cash Flows Used For Investing Activities	(81,909)	(114,485)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	6,080	494,375
Issuance of Long-term Debt - Affiliated	200,000	-
Change in Advances to/from Affiliates, Net	(100,222)	232,881
Change in Short-term Debt, Net	(4,402)	-
Change in Short-term Debt - Affiliates, Net	-	(275,000)
Retirement of Long-term Debt - Nonaffiliated	(204,427)	(29,850)
Retirement of Long-term Debt - Affiliated	-	(300,000)
Retirement of Cumulative Preferred Stock	(2,251)	(502)
Dividends Paid on Common Stock	(114,115)	(83,867)
Dividends Paid on Cumulative Preferred Stock	(366)	(629)
Net Cash Flows (Used For) From Financing Activities	(219,703)	37,408
Net Increase (Decrease) in Cash and Cash Equivalents	(839)	3,390
Cash and Cash Equivalents at Beginning of Period	7,233	5,275
Cash and Cash Equivalents at End of Period	$6,394	$8,665

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $60,282,000 and $29,304,000 and for income taxes was $(8,420,000) and $26,455,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's consolidated financial statements are combined with the notes to 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 $20 million for 2004 year-to-date, and $11 million for the second quarter due mainly to increased expenses for power plant maintenance, tree trimming, line clearance and storm damage repairs.

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.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income decreased $12 million primarily due to:

o Decreased retained margins of $2 million due mainly to decreased realization of off-system sales.
o Decreased transmission revenues of $2 million due mainly to non-affiliated transactions.
o Increased Other Operation expenses of $5 million primarily related to affiliated ancillary services, general transmission and distribution related expenses.
o Increased Maintenance expense of $11 million due mainly to increased power plant maintenance and tree trimming, along with increased repairs due to storm damage.
o Increased Taxes Other Than Income Taxes of $1 million due primarily to higher property and unemployment related taxes, offset in part by lower state franchise taxes.

The decrease in Operating Income was partially offset by:

o Increased retail base revenue of $8 million (5%), resulting mainly from increased KWH sales of 8%. Heating and cooling degree-days increased 12%.

Other Impacts on Earnings

Interest Charges decreased $2 million due to reduced interest rates from refinancing higher cost debt.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 21.0% and 18.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to higher state income taxes offset by lower pre-tax income in 2004.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income decreased $24 million primarily due to:

o Decreased retained margins of $4 million due mainly to decreased realization of off-system sales.
o Decreased transmission revenues of $3 million due mainly to non-affiliated transactions.
o Increased Other Operation expenses of $17 million, of which $9 million was transmission expense primarily related to a prior year true up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003. Increased distribution expenses of $5 million resulting mainly from a labor settlement and various inventory and tracking system upgrades. Increased administrative and general expenses resulted from outside services and employee related expenses.
o Increased Maintenance expense of $14 million due mainly to increased power plant maintenance and tree trimming along with increased repairs due to storm damage. The decrease in Operating Income was partially offset by:

o Increased retail base revenue of $9 million (5%), resulting mainly from increased KWH sales of 3%. Total heating and cooling degree-days decreased 9%, but overall customer usage not related to weather increased, as did the number of customers.

Other Impacts on Earnings

Interest Charges decreased $5 million due to reduced interest rates from refinancing higher cost debt.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 78.1% and 15.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The increase in the effective tax rate is primarily due to pre-tax income becoming a loss in 2004 and state income taxes.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our first mortgage bonds were upgraded by S&P to A- due to a change in methodology at the agency. Current ratings are as follows:

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

Financing Activity

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

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$33,700	Variable	2014
Senior Unsecured Notes	50,000	4.70	2009

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable to Trust	$77,320	8.00	2037
Installment Purchase Contracts	33,700	4.875	2014

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(973)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	62
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)	(9,327)
Total MTM Risk Management Contract Net Assets	3,819
Net Cash Flow Hedge Contracts (f)	(567)
Total MTM Risk Management Contract Net Assets at June 30, 2004	$3,252

(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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(379)	$38	$(1)	$120	$-	$-	$(222)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,468	795	158	-	-	-	2,421

Prices Based on Models and Other Valuation Methods (b)	(90)	618	(45)	119	256	762	1,620
Total	$999	$1,451	$112	$239	$256	$762	$3,819

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Six Months Ended June 30, 2004

(in thousands)	Power
Beginning Balance December 31, 2003	$156
Changes in Fair Value (a)	(426)
Reclassifications from AOCI to Net Income (b)	(100)
Ending Balance June 30, 2004	$(370)

(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 $236 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$97	$221	$110	$55	$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 $45 million and $66 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$228,653	$267,213	$432,696	$505,480
Sales to AEP Affiliates	2,954	10,023	6,096	14,418
TOTAL	231,607	277,236	438,792	519,898
OPERATING EXPENSES				
Fuel for Electric Generation	87,006	135,395	176,091	238,569
Purchased Electricity for Resale	5,583	6,863	14,751	19,354
Purchased Electricity from AEP Affiliates	28,200	28,276	55,099	70,383
Other Operation	36,768	31,684	80,163	63,302
Maintenance	22,875	12,366	35,997	21,760
Depreciation and Amortization	22,159	21,359	44,335	42,853
Taxes Other Than Income Taxes	9,727	8,439	19,544	18,085
Income Taxes (Credits)	2,429	4,139	(4,904)	3,731
TOTAL	214,747	248,521	421,076	478,037
OPERATING INCOME	16,860	28,715	17,716	41,861
Nonoperating Income	127	72	371	722
Nonoperating Expense (Credit)	762	(276)	1,304	163
Nonoperating Income Tax (Credit)	(467)	(155)	(859)	(355)
Interest Charges	9,301	11,291	19,254	24,157
NET INCOME (LOSS)	7,391	17,927	(1,612)	18,618
Preferred Stock Dividend Requirements	53	53	106	106
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$7,338	$17,874	$(1,718)	$18,512

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(7,500)		(7,500)
Preferred Stock Dividends			(106)		(106)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent			(548)		(548)
TOTAL					441,093
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(879)	(879)
Minimum Pension Liability				(58)	(58)
NET INCOME			18,618		18,618
TOTAL COMPREHENSIVE INCOME					17,681
JUNE 30, 2003	$157,230	$230,016	$126,938	$(55,410)	$458,774
DECEMBER 31, 2003	$157,230	$230,016	$139,604	$(43,842)	$483,008
Gain on Reacquired Preferred Stock			2		2
Common Stock Dividends			(17,500)		(17,500)
Preferred Stock Dividends			(106)		(106)
TOTAL					465,404
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(526)	(526)
NET LOSS			(1,612)		(1,612)
TOTAL COMPREHENSIVE INCOME (LOSS)					(2,138)
JUNE 30, 2004	$157,230	$230,016	$120,388	$(44,368)	$463,266

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,068,770	$1,065,408
Transmission	453,936	451,292
Distribution	1,061,487	1,031,229
General	208,736	203,756
Construction Work in Progress	41,446	54,711
TOTAL	2,834,375	2,806,396
Accumulated Depreciation and Amortization	1,097,590	1,069,216
TOTAL - NET	1,736,785	1,737,180
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,411	4,631
Other Investments	-	2,320
TOTAL	4,411	6,951
CURRENT ASSETS		
Cash and Cash Equivalents	3,843	3,738
Other Cash Deposits	6,954	10,520
Accounts Receivable:		
Customers	29,892	28,515
Affiliated Companies	20,889	19,852
Miscellaneous	3,017	-
Allowance for Uncollectible Accounts	(27)	(37)
Fuel Inventory	21,083	18,331
Materials and Supplies	38,930	38,125
Regulatory Asset for Under-recovered Fuel Costs	36,853	24,170
Risk Management Assets	6,632	18,586
Margin Deposits	374	4,351
Prepayments and Other	2,700	2,655
TOTAL	171,140	168,806
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	15,517	14,357
Other	12,351	14,342
Long-term Risk Management Assets	3,831	10,379
Deferred Charges	35,239	18,017
TOTAL	66,938	57,095
TOTAL ASSETS	$1,979,274	$1,970,032

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	120,388	139,604
Accumulated Other Comprehensive Income (Loss)	(44,368)	(43,842)
Total Common Shareholder's Equity	463,266	483,008
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267
Total Shareholder's Equity	468,528	488,275
Long-term Debt	447,018	490,598
TOTAL	915,546	978,873
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	100,000	83,700
Advances from Affiliates	75,034	32,864
Accounts Payable:		
General	64,367	48,808
Affiliated Companies	61,981	57,206
Customer Deposits	29,499	26,547
Taxes Accrued	35,068	27,157
Interest Accrued	3,447	3,706
Risk Management Liabilities	5,034	11,067
Obligations Under Capital Leases	494	452
Other	21,294	35,234
TOTAL	396,218	326,741
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	347,414	335,434
Long-Term Risk Management Liabilities	2,177	3,602
Regulatory Liabilities:		
Asset Removal Costs	219,101	214,033
Deferred Investment Tax Credits	29,515	30,411
SFAS 109 Regulatory Liability, Net	23,719	24,937
Other	5,085	15,406
Obligations Under Capital Leases	620	558
Deferred Credits and Other	39,879	40,037
TOTAL	667,510	664,418
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,979,274	$1,970,032

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income (Loss)	$(1,612)	$18,618
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	44,335	42,853
Deferred Income Taxes	11,043	10,940
Deferred Investment Tax Credits	(895)	(895)
Deferred Property Taxes	(17,295)	(16,478)
Mark-to-Market of Risk Management Contracts	10,237	(12,340)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(5,441)	(5,556)
Fuel, Materials and Supplies	(3,557)	868
Accounts Payable	20,334	1,262
Taxes Accrued	7,911	5,780
Fuel Recovery	(12,683)	11,650
Changes in Other Assets	157	(11,359)
Changes in Other Liabilities	(16,478)	1,145
Net Cash Flows From Operating Activities	36,056	46,488
INVESTING ACTIVITIES		
Construction Expenditures	(36,645)	(34,660)
Proceeds from Sale of Property and Other	458	127
Change in Other Cash Deposits, Net	3,566	(2,843)
Net Cash Flows Used For Investing Activities	(32,621)	(37,376)
FINANCING ACTIVITIES		
Capital Contributions from Parent	-	50,000
Change in Advances to/from Affiliates, Net	42,170	(17,550)
Retirement of Long-term Debt	(111,020)	(35,000)
Issuance of Long-term Debt	83,129	-
Reacquired Preferred Stock	(3)	-
Dividends Paid on Common Stock	(17,500)	(7,500)
Dividends Paid on Cumulative Preferred Stock	(106)	(106)
Net Cash Flows Used For Financing Activities	(3,330)	(10,156)
Net Increase (Decrease) in Cash and Cash Equivalents	105	(1,044)
Cash and Cash Equivalents at Beginning of Period	3,738	9,543
Cash and Cash Equivalents at End of Period	$3,843	$8,499

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $17,600,000 and $24,107,000 and for income taxes was $(2,695,000) and $8,975,000 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 Financial Statements of Registrant Subsidiaries beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other 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 $7 million for 2004 year-to-date, but increased $7 million for the second quarter. The year-to-date decrease is due in large part to a decline in margins from risk management activities and the $9 million (net of tax) Cumulative Effect of Accounting Changes recorded in 2003. For the quarter, the decreased risk management margins were more than offset by increased retail revenues and a purchased power refund.

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.

Second Quarter 2004 Compared to Second Quarter 2003

Operating Income

Operating Income increased by $6 million primarily due to:

o Increased retail base revenues of $8 million due to an increased number of customers and their average usage, offset in part by milder weather.
o Decreased fuel expense of 10% due both to lower KWH generation of 4% and lower cost per KWH of 6%.
o Decreased purchased power of 88% due mainly to a refund of capacity payments for prior periods of $8.6 million. Additionally, KWH purchases declined 17% and the cost per KWH declined by 38%.

The increase in Operating Income was partially offset by:

o Decreased retained margins from off-system sales of $2 million due to mainly to decreased realization of off-system sales.
o Decreased margins from risk management activities of $6 million.
o Increased Other Operation expenses of $2 million primarily related to transmission expense.
o Increased Maintenance expense of $5 million resulting from $3 million of overhead line expense primarily related to storm damage, as well as scheduled power plant maintenance.
o Increased Taxes Other Than Income Taxes of $2 million due primarily to higher property taxes.

Other Impacts on Earnings

Interest Charges decreased $2 million as a result of refinancing higher interest rate debt and trust preferred securities with lower cost debt and trust preferred securities.

Minority Interest of $1 million is a result of consolidating Sabine Mining Company (Sabine) effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabine's revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected.

Income Taxes

The effective tax rates for the second quarter of 2004 and 2003 were 33.2% and 32.9%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Operating Income

Operating Income was virtually unchanged but negatively impacted by:

o Decreased retained margins from off-system sales of $2 million due mainly to decreased realization of off-system sales.
o Decreased margins from risk management activities of $9 million.
o Increased Other Operation expenses of $8 million primarily related to a prior year true up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003 offset in part by lower administrative expenses.
o Increased Maintenance expense of $8 million primarily related to scheduled power plant maintenance, as well as increased overhead

line maintenance, partly due to increased storm damage.
o Increased Depreciation and Amortization expense of $4 million due primarily to the restoration in 2003 of a regulatory asset related to the recovery of fuel related cost in Arkansas.
o Increased Taxes Other Than Income Taxes of $3 million due primarily to higher property taxes and state and local franchise taxes.

Operating Income was positively affected by:

o Increased retail base revenues of $12 million, 5%, due to an increased number of customers and their average usage, offset in part by milder weather. Cooling and heating degree-days decreased 4%.
o Total purchased power decreased by 66% due mainly to a refund of capacity payments for prior periods of $8.6 million. Additionally, KWH purchases declined 19% and the cost per KWH declined 20%.

Other Impacts on Earnings

Interest Charges decreased $3 million as a result of refinancing higher interest rate debt and trust preferred securities with lower cost debt and trust preferred securities.

Minority Interest of $2 million is a result of consolidating Sabine effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabine's revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected.

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.

Income Taxes

The effective tax rates for the first six months of 2004 and 2003 were 29.3% and 33.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to permanent differences relating to book depletion and Medicare subsidy.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our first mortgage bonds were upgraded by S&P to A- due to a change in methodology at the agency. Current ratings are as follows:

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

Cash Flow

Cash flows for the six months ended June 30, 2004 and 2003 were as follows:

	2004	2003
Cash and cash equivalents at beginning of period	$5,676	$-
Cash flows from (used for):		
Operating activities	113,340	114,574

Investing activities	(57,360)	(63,575)
Financing activities	(50,054)	(43,674)
Net increase in cash and cash equivalents	5,926	7,325
Cash and cash equivalents at end of period	$11,602	$7,325

Operating Activities

Cash Flows From Operating Activities were $113 million primarily due to Net Income, Accounts Payable, Fuel Recovery and Taxes Accrued offset in part by Accounts Receivable, Net and Other Assets and Liabilities.

Investing Activities

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

Financing Activities

Cash Flows Used For 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 six months of 2004 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$53,500	Variable	2019
Installment Purchase Contracts	41,135	Variable	2011
Financing Obligations	14,226	5.77	2024

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$53,500	7.60	2019
Installment Purchase Contracts	12,290	6.90	2004

Installment Purchase Contracts 2008	12,170	6.00
Installment Purchase Contracts 2011	17,125	8.20
First Mortgage Bonds 2025	80,000	6.875
First Mortgage Bonds 2004	40,000	7.75
Notes Payable 2011	3,415	4.47
Notes Payable 2008	1,500	Variable

Significant Factors

See the "Registrant Subsidiaries' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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
Six Months Ended June 30, 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)	(3,571)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	73
Change in Fair Value Due to Valuation Methodology Changes (d)	62
Changes in Fair Value of Risk Management Contracts (e)	(1,720)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(7,027)
Total MTM Risk Management Contract Net Assets	4,423
Net Cash Flow Hedge Contracts (g)	(1,309)
Total MTM Risk Management Contract Net Assets at June 30, 2004	$3,114

(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) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

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

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

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 June 30, 2004

	Remainder 2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted - Exchange Traded Contracts	$(446)	$44	$(1)	$142	$-	$-	$(261)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,729	936	186	-	-	-	2,851
Prices Based on Models and Other Valuation Methods (b)	(181)	727	(53)	141	301	898	1,833
Total	$1,102	$1,707	$132	$283	$301	$898	$4,423

(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

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 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. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133 only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity For the Six Months Ended June 30, 2004

	Power
	(in thousands)
Beginning Balance December 31, 2003	$184
Changes in Fair Value (a)	(500)
Reclassifications from AOCI to Net Income (b)	(118)
Ending Balance June 30, 2004	$(434)

(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 $278 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:

Six Months Ended June 30, 2004 (in thousands)				Twelve Months Ended December 31, 2003 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$115	$260	$129	$65	$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 $40 million and $57 million at June 30, 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 and Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended		Six Months Ended	
	2004	2003	2004	2003
	(in thousands)			
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$251,230	$263,907	$465,179	$487,521
Sales to AEP Affiliates	17,498	17,399	39,709	49,063
TOTAL	268,728	281,306	504,888	536,584
OPERATING EXPENSES				
Fuel for Electric Generation	94,245	104,979	183,068	204,618
Purchased Electricity for Resale	(4,008)	10,365	1,926	22,932
Purchased Electricity from AEP Affiliates	7,113	14,841	14,420	25,651
Other Operation	44,273	42,383	94,540	86,611
Maintenance	24,011	18,931	39,659	31,748
Depreciation and Amortization	31,979	30,868	63,264	58,903
Taxes Other Than Income Taxes	15,148	13,168	31,715	29,041
Income Taxes	14,439	10,183	14,570	15,448
TOTAL	227,200	245,718	443,162	474,952
OPERATING INCOME	41,528	35,588	61,726	61,632
Nonoperating Income	792	475	2,195	1,347
Nonoperating Expenses	1,240	355	2,066	876
Nonoperating Income Tax (Credit)	(541)	(105)	(897)	(55)
Interest Charges	12,862	15,223	28,090	31,077
Minority Interest	813	-	1,694	-
Income Before Cumulative Effect of Accounting Changes	27,946	20,590	32,968	31,081
Cumulative Effect of Accounting Changes (Net of Tax)	-	-	-	8,517
NET INCOME	27,946	20,590	32,968	39,598
Preferred Stock Dividend Requirements	58	58	115	115
EARNINGS APPLICABLE TO COMMON STOCK	$27,888	$20,532	$32,853	$39,483

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Six Months Ended June 30, 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			(36,396)		(36,396)
Preferred Stock Dividends			(115)		(115)
TOTAL					625,258
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(1,004)	(1,004)
NET INCOME			39,598		39,598
TOTAL COMPREHENSIVE INCOME					38,594
JUNE 30, 2003	$135,660	$245,003	$337,876	$(54,687)	$663,852
DECEMBER 31, 2003	$135,660	$245,003	$359,907	$(43,910)	$696,660
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(115)		(115)
TOTAL					666,545
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges				(618)	(618)
Minimum Pension Liability				23,066	23,066
NET INCOME			32,968		32,968
TOTAL COMPREHENSIVE INCOME					55,416
JUNE 30, 2004	$135,660	$245,003	$362,760	$(21,462)	$721,961

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2004 and December 31, 2003
(Unaudited)

	2004	2003
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,657,785	$1,622,498
Transmission	629,662	615,158
Distribution	1,097,960	1,078,368
General	445,896	423,427
Construction Work in Progress	31,100	60,009
TOTAL	3,862,403	3,799,460
Accumulated Depreciation and Amortization	1,673,188	1,617,846
TOTAL - NET	2,189,215	2,181,614
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,050	3,808
Other Investments	4,710	4,710
TOTAL	8,760	8,518
CURRENT ASSETS		
Cash and Cash Equivalents	11,602	5,676
Other Cash Deposits	5,245	6,048
Advances to Affiliates	-	66,476
Accounts Receivable:		
Customers	42,103	41,474
Affiliated Companies	17,484	10,394
Miscellaneous	4,018	4,682
Allowance for Uncollectible Accounts	(4,675)	(2,093)
Fuel Inventory	59,898	63,881
Materials and Supplies	35,675	33,775
Regulatory Asset for Under-recovered Fuel Costs	4,822	11,394
Risk Management Assets	7,734	19,715
Margin Deposits	437	5,123
Prepayments and Other	18,252	19,078
TOTAL	202,595	285,623
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	5,281	3,235
Unamortized Loss on Reacquired Debt	22,161	19,331
Minimum Pension Liability	35,486	-
Other	15,195	15,859
Long-term Risk Management Assets	4,512	12,178
Deferred Charges	71,580	55,605
TOTAL	154,215	106,208
TOTAL ASSETS	$2,554,785	$2,581,963

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 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	362,760	359,907
Accumulated Other Comprehensive Income (Loss)	(21,462)	(43,910)
Total Common Shareholder's Equity	721,961	696,660
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholder's Equity	726,661	701,360
Long-term Debt	763,486	741,594
TOTAL	1,490,147	1,442,954
Minority Interest	1,280	1,367
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	10,244	142,714
Advances from Affiliates	26,918	-
Accounts Payable:		
General	43,740	37,646
Affiliated Companies	32,558	35,138
Customer Deposits	26,731	24,260
Taxes Accrued	75,180	28,691
Interest Accrued	11,848	16,852
Risk Management Liabilities	6,239	11,361
Obligations Under Capital Leases	3,420	3,159
Regulatory Liability for Over-recovered Fuel	6,204	4,178
Other	32,867	53,753
TOTAL	275,949	357,752
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	358,813	349,064
Long-term Risk Management Liabilities	2,893	4,667
Reclamation Reserve	7,632	16,512
Regulatory Liabilities:		
Asset Removal Costs	243,305	236,409
Deferred Investment Tax Credits	37,701	39,864
Excess Earnings	2,600	2,600
Other	7,870	18,779
Asset Retirement Obligations	26,665	8,429
Obligations Under Capital Leases	18,139	18,383
Deferred Credits and Other	81,791	85,183
TOTAL	787,409	779,890
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,554,785	$2,581,963

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
	(in thousands)	
OPERATING ACTIVITIES		
Net Income	$32,968	$39,598
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Cumulative Effect of Accounting Changes	-	(8,517)
Depreciation and Amortization	63,264	58,903
Deferred Income Taxes	(4,519)	2,413
Deferred Investment Tax Credits	(2,163)	(2,163)
Deferred Property Taxes	(19,375)	(18,630)
Mark-to-Market of Risk Management Contracts	12,181	(13,945)
Changes in Certain Assets and Liabilities:		
Accounts Receivable, Net	(4,473)	9,696
Fuel, Materials and Supplies	2,083	7,445
Accounts Payable	3,514	(12,349)
Taxes Accrued	46,489	23,792
Fuel Recovery	8,598	(14,148)
Change in Other Assets	(6,049)	10,887
Change in Other Liabilities	(19,178)	31,592
Net Cash Flows From Operating Activities	113,340	114,574
INVESTING ACTIVITIES		
Construction Expenditures	(60,479)	(62,883)
Proceeds from Sale of Assets and Other	2,316	414
Change in Other Cash Deposits, Net	803	(1,106)
Net Cash Flows Used For Investing Activities	(57,360)	(63,575)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	106,667	143,041
Retirement of Long-term Debt	(220,000)	(56,020)
Change in Advances to/from Affiliates, Net	93,394	(94,184)
Dividends Paid on Common Stock	(30,000)	(36,396)
Dividends Paid on Cumulative Preferred Stock	(115)	(115)
Net Cash Flows Used For Financing Activities	(50,054)	(43,674)
Net Increase in Cash and Cash Equivalents	5,926	7,325
Cash and Cash Equivalents at Beginning of Period	5,676	-
Cash and Cash Equivalents at End of Period	$11,602	$7,325

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $29,841,000 and $27,741,000 and for income taxes was $3,220,000 and $17,062,000 in 2004 and 2003, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's consolidated financial statements are combined with the notes to financial statements for other subsidiary registrants. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for AEP's registrant subsidiaries. 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.	Dispositions and 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	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, 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	June 30, 2004	December 31, 2003
	(in thousands)	
Cash Flow Hedges:		
APCo	$(6,031)	$(1,569)
CSPCo	(2,195)	202
I&M	(2,756)	222
KPCo	(542)	420
OPCo	(3,345)	(103)
PSO	(370)	156
SWEPCo	(434)	184
TCC	(11,242)	(1,828)
TNC	(3,765)	(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	Liabilities Incurred	Balance at June 30, 2004
		(in millions)		
AEGCo (a)	$1.1	$0.1	$-	$1.2
APCo (a)	21.7	0.9	-	22.6
CSPCo (a)	8.7	0.4	-	9.1
I&M (b)	553.2	19.6	-	572.8
OPCo (a)	42.7	1.6	-	44.3
SWEPCo (d)	8.4	0.6	17.7	26.7
TCC (c)	218.8	8.2	-	227.0

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.2 million at June 30, 2004) and nuclear decommissioning costs for the Cook Plant ($571.6 million at June 30, 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 and Dolet Hills.

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

As of June 30, 2004 and December 31 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $885 million ($754 million for I&M and $131 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 (Loss).

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. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106's 10 percent corridor. The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million. The tax-free subsidy reduced AEP's second quarter net periodic postretirement benefit cost by a total of $7 million, including $3 million of amortization of the actuarial gain, $1 million of reduced service cost, and $3 million of reduced interest cost on the APBO. After adjustment to capitalization of employee benefits costs as of a cost of construction projects, $5 million of this tax-free cost reduction remained to increase AEP's second quarter net income.

The following table provides the reduction in the net periodic postretirement benefit cost for the second quarter of 2004 for the AEP registrant subsidiaries:

	Postretirement Benefit Cost Reduction (in thousands)
APCo	$815
CSPCo	413
I&M	632
KPCo	121
OPCo	720
PSO	281
SWEPCo	291
TCC	327
TNC	143

The effect of implementing FSP FAS 106-2 on AEP for the first quarter of 2004 is as follows:

Three Months Ended March, 31, 2004	Earnings in Millions	Earnings Per Share
Originally Reported	$278	$0.70
Effect of Medicare Subsidy	5	0.02
Restated	$283	$0.72

The effect of implementing FSP FAS 106-2 by the following AEP registrant subsidiaries for the first quarter of 2004 is as follows:

	Originally Reported Net Income (Loss)	Effect of Medicare Subsidy	Restated Net Income (Loss)
		(in thousands)	
APCo	$64,521	$815	$65,336
CSPCo	44,705	413	45,118
I&M	42,376	632	43,008
KPCo	11,490	121	11,611
OPCo	79,444	720	80,164
PSO	(9,284)	281	(9,003)
SWEPCo	4,730	291	5,021

TCC	29,077	327	29,404
TNC	12,953	143	13,096

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including discontinued operations, business combinations, liabilities and equity, revenue recognition, accounting for equity-based compensation, pension plans, asset retirement obligations, earnings per share calculations, fair value measurements, 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, rate and regulatory proceedings at the FERC and at several state commissions are ongoing. 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 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 from July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory.

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: (1) 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 (2) 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.

In December 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 in January 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 May 2004, the PUCT reversed its position on the inclusion of MTM amounts in the allocation of system sales margins and remanded the case to the ALJ. As a result, TNC recorded an additional provision of $12 million in the second quarter of 2004 resulting in an over-recovery balance of $7 million at June 30, 2004.

On July 2, 2004, the parties to the MTM remand proceeding filed a "Stipulation of Fact." All parties agreed to the amount of the remanded issue. If the amounts included in the "Stipulation of Fact" are approved, the over-recovery balance will be reduced to $4 million. We expect the PUCT to issue its final order in this proceeding in August 2004.

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 from July 1998 through December 2001.

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. In May 2004, the PUCT accepted most of the ALJ's recommendations. The PUCT rejected the ALJ's recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy- only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues.

Hearings are scheduled in October 2004 for the remand issue. As a result of the PUCT's acceptance of the ALJ's recommendations and the PUCT's remand decision in the TNC case regarding the inclusion of MTM amounts in the allocation of AEP's net system sales margins, TCC increased its provision by $47 million in the second quarter of 2004. The over-recovery balance and the provisions total $210 million including interest at June 30, 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 and cash flows. 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 the SPP. This reconciliation covers the period from 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 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%. In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a non-unanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCC's rate request to $41 million. The ALJs that heard the case issued their recommendations on July 2, 2004 including a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded for additional evidence. On July 15, 2004, the PUCT agreed to remand this issue to the ALJs. In addition, the PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCC's calculations, the ALJs' recommendations reduce TCC's existing rates by a range of $33 million to $43 million depending on the final resolution of the amount of consolidation tax savings. TCC filed exceptions to the ALJs' recommendations on July 21, 2004. The PUCT is expected to issue its decision in September 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates, revenues, 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 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 if a rate reduction is ordered, would adversely impact results of operations and cash flows.

PSO Fuel and Purchased Power - Affecting PSO

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the Corporation Commission of the State of Oklahoma (OCC) seeking to recover these costs over a period of 18 months. 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 between and among AEP operating companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and could more than offset the $44 million 2002 reallocation. The intervenor and the OCC Staff also believed trading margins were allocated incorrectly and that a reallocation by the intervenors of such margins would reduce PSO's recoverable fuel by approximately $6.8 million for 2000 and $10.7 million for 2001, while under the OCC Staff method, the amount for 2001 would be $8.8 million. The intervenor and the OCC Staff also recommend recalculation of fuel for years subsequent to 2001 using the same methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were the jurisdiction of the OCC or the FERC because they relate to the FERC-approved agreements. As a result, the ALJ ordered that the jurisdictional issue be briefed by the parties. PSO is required to file its brief by September 1, 2004. Subject to decisions by the OCC as to jurisdiction, a hearing date has been set for January 2005. 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 - 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 $33 million of RTO formation and integration costs and related carrying charges through June 30, 2004. Amounts per company are as follows:

Company	(in millions)
APCo	$9.4
CSPCo	3.9
I&M	7.2
KPCo	2.2
OPCo	10.3

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 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 prudently incurred deferred RTO formation/integration 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 as these companies file rate cases. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo.

In August 2004, we intend to file an application with FERC dividing the RTO information/integration costs between payments made to PJM and all other costs. We will subsequently request that the payments made directly to PJM be recovered from all users of PJM's transmission and that the balance of the deferred costs be recovered from load serving entities within the area served by the AEP East companies' owned transmission (AEP zone). Most of the amount recoverable in the AEP zone will be paid by the AEP East companies since it will be attributable to their internal load. The amount to be recovered in the AEP zone is approximately one-half of the deferred costs. In our August application, we will seek permission to delay the amortization of the AEP zone deferred amounts until they are recoverable from users of the transmission system including our retail customers or, as an alternative, to use a long amortization period that extends beyond the rate freezes or caps.

The AEP East companies are scheduled to join PJM in October 2004, although there are pending proceedings in Virginia concerning the 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 or a long enough amortization period to allow for the opportunity for recovery in the East retail jurisdictions. 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 project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or a long amortization period or the FERC or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM. In July 2004, after reaching a unanimous agreement with intervenors to settle the RTO issues in Virginia, the settlement agreement was submitted to the Virginia SCC. The settlement provides for approval of APCo's application to join PJM in exchange for a small annual revenue credit to customers through 2010, or the effective date of rates established in a new base rate case, some service curtailment provisions and annual reporting requirements.

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 approved the agreement in May 2004 and the FERC approved the settlement in June 2004.

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

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 issued an order related to this matter in June 2004 affirming its preliminary findings. Virginia has requested a stay of the FERC order, which was denied, and Virginia now has requested a stay in the courts.

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 August 27, 2003, the IURC ordered that certain parties must negotiate the appropriate action on I&M's fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant outage issues). The fixed fuel adjustment charge capped fuel recoveries. In an agreement in connection with AEP's planned corporate separation, I&M agreed, contingent on AEP implementing the corporate separation, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although AEP has not corporately separated, certain parties believe the fixed fuel adjustment charge should continue. Negotiations with the parties to resolve 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 to actual fuel costs following the resolution of issues in the corporate separation agreement. The IURC also issued an order that reopened the corporate separation docket to investigate issues related to the corporate separation agreement. On July 15, 2004, we filed a fuel factor for the period October 2004 through March 2005. If the IURC reinstates a fixed fuel adjustment factor, capping the fuel revenues, results of operations and cash flows would be adversely affected if fuel costs are under-recovered.

Michigan 2004 Fuel Recovery Plan - Affecting I&M

A 1999 Michigan Public Service Commission's (MPSC) 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. 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 occurred on March 10, 2004 and a MPSC order is expected during the second half of 2004. One June 4, 2004, an ALJ recommended that SO2 and NOx costs be excluded. I&M filed exception on June 18, 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 cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

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 (MBSSO) 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 (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between them MBSSO or the CBP. Customers who make no choice will be served pursuant to the CBP. CSPCo and OPCo were granted a waiver from making the required MBSSO/CBP filing, as a result of their rate stabilization plan filing.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing prices following the end of the MDP. If approved by the PUCO, prices would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008. The plan is intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. 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 prior to December 31, 2005 as permitted by the Ohio Act, the fixed increases would be 1.6% for CSPCo and

5.7% for OPCo. Any additional 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 governmentally mandated, mainly environmental, capital expenditures. Hearings were held in June 2004. Briefings were completed in July and the cases are pending before the PUCO. 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. Through June 30, 2004, CSPCo incurred $35 million and deferred $15 million and OPCo incurred $37 million and deferred $17 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 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The 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.

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 PROCEEDINGS

The 2004 true-up proceedings will determine the amount and recovery of:
o net stranded generation plant costs and generation-related regulatory assets (stranded plant costs),
o carrying charges on stranded plant costs from January 2002 (the commencement date of retail competition),
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 TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later. TNC filed its 2004 true-up proceeding in June 2004.

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        Summary of TCC True-up Items:
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                                                                        Amount Recorded
                                                                        at June 30,
        2004

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	(in millions)	
Stranded Generation Plant Costs	$1,074	(a)
Unsecuritized Transition Regulatory Asset	194	(a)
Unrefunded Excess Earnings	(19)	(b)
Other	(46)	
Amount Subject to Future Securitization	1,203	
Wholesale Capacity Auction True-up	480	(c)
Retail Clawback	(30)	(d)
Deferred Over-recovered Fuel	(210)	(e)
Other Recoverable Amounts	240	
Total Recorded 2004 True-up Balance	$1,443	(f)

(a) See "Stranded Costs and Generation-Related Regulatory Assets" section below for additional information on this item.
(b) See "Unrefunded Excess Earnings" section below for additional information on this item.
(c) See "Wholesale Capacity Auction True-up" section below for additional information on this item.
(d) See "Retail Clawback" section below for additional information on this item.
(e) See "Fuel Balance Recoveries" section below for additional information on this item.
(f) See "Stranded Cost Recovery" section below for summary of this balance.

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. TCC elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. 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. Based on the prices established by the sales, discussed below, TCC's stranded costs from the sale of generation assets and remaining generation-related net regulatory assets are estimated to be $1.3 billion ($1,074 million and $194 million, described later in this section) before accrual of any applicable carrying charges.

In June 2003, TCC began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas with a net book value of $1.9 billion at June 30, 2004. We received bids for all of TCC's generation plants. In January 2004, TCC agreed to sell its 7.81% 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% ownership interest 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 to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion and the fossil and hydro plants. TCC received a notice from a co-owner of Oklaunion and STP exercising their right of first refusal; therefore, SEC approval will be required. The original unaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and that the co-owners' rights of first refusal are void. Approval of the sale of STP from the Nuclear Regulatory Commission is required. On July 1, 2004, we completed the sale of the other coal, gas and hydro plants for approximately $425 million, net of adjustments. The completion of the sales of STP and Oklaunion plants is expected to occur in 2004, subject to rights of first refusal and the necessary regulatory approvals. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. TCC will file its 2004 true-up proceeding with the PUCT after the completion of the sale of the generation assets.

After the 2004 true-up proceeding, TCC may recover stranded costs and other true-up amounts through distribution rates as a competition transition charge and may seek to issue securitization revenue bonds for its stranded plant costs and remaining generation net regulatory assets. The cost of the securitization bonds is recovered through distribution rates as a separate transition charge. TCC recognized an impairment of its generation assets in December 2003 as a regulatory asset. At June 30, 2004, this regulatory asset was approximately $1,074 million. The recovery of this regulatory asset and the remaining $194 million of generation-related net regulatory assets will be subject to review and approval by the PUCT as a stranded plant cost in the 2004 true-up proceeding.

Carrying Charges On Recoverable Stranded Costs

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the 2004 true-up proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the companies, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and the PUCT should address whether the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs. Industrial intervenors have filed a motion for rehearing with the Supreme Court which has not been decided.

The PUCT has indicated that it will consider the Supreme Court's decision in hearings to be held for another utility in September 2004. The decision in that proceeding could have an impact on TCC. Since the impact of these future PUCT proceedings cannot be determined at this time, TCC has not recorded the carrying charge as a regulatory asset through June 30, 2004.

Wholesale Capacity Auction True-up

Texas Legislation required 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. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. 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. The PUCT issued a written order in March 2004 that established TNC's unrecovered fuel balance for the ERCOT service territory. Various parties, including TNC, requested rehearing of the PUCT's order. In May 2004, the PUCT reversed certain prior rulings resulting in TNC having a final fuel over-recovery balance of approximately $7 million. TNC's 2004 true-up proceeding, filed in June 2004, will be updated to reflect the balance after the PUCT issues a final fuel order. TNC has provided for all to-date disallowances pending receipt of the final order. Management is unable to predict the amount of TNC's fuel over-recovery which will be included in its 2004 true-up proceedings.

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 May 2004, the PUCT remanded TCC's fuel proceeding to the ALJ. TCC has provided $210 million for its over-recovery balance at June 30, 2004. TCC has provided for all to-date disallowances pending receipt of a final order. 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 ($19 million at June 30, 2004). 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 ultimate 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. Based upon customer information filed by the unaffiliated company which operates as the affiliated REP for TCC and TNC, we updated the estimated retail clawback regulatory liability in May 2004. At June 30, 2004, the retail clawback regulatory liability was $30 million for TCC and $7 million for TNC.

TNC 2004 True-up Filing

In June 2004, TNC filed its 2004 true-up proceeding including the fuel reconciliation balance and the retail clawback calculation. The amount of deferred fuel, an over-recovery balance of $7 million at June 30, 2004, remains under review by the PUCT and is subject to possible revision. The retail clawback regulatory liability was adjusted in the second quarter of 2004 to $7 million (TNC's allocated portion of the REP's retail clawback) reflecting the number of customers served on January 1, 2004. The PUCT has deferred this proceeding pending the resolution of the final fuel proceeding.

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, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize the approved stranded plant costs and generation-related net regulatory assets that were not previously recovered through a prior securitization and the non-bypassable transition charge. The annual costs of securitization are recovered through the non-bypassable transition charge collected by the T&D utility over the term of the securitization bonds.

TCC's recorded net regulatory asset for amounts subject to approval in the 2004 true-up proceeding is approximately $1.4 billion. Management estimates that TCC's 2004 true-up filing will exceed the total of its recorded net regulatory asset. Management expects that the 2004 true-up proceeding will be contentious and could possibly result in disallowances.

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 net regulatory assets, 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 - Affecting APCo

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 optional general based rate changes and an opportunity for recovery, through a separate rate mechanism, 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) potential uninsured losses, (4) merger litigation, 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 June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Muskingum River, Cardinal, Conesville and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA is expected to file a motion to amend its complaint, and, to the extent that motion seeks to expand the scope of the pending litigation, the AEP subsidiaries will oppose that motion.

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 was scheduled for July 2004, but has been postponed until January 2005 to facilitate further settlement negotiations.

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. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals, which issued a briefing order requiring the case to be fully briefed by late September 2004.

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 any contingent liability the AEP subsidiaries might have for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If 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.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input valve, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input valve in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, and the referenced recordkeeping and reporting requirements and heat input valve at Welsh. SWEPCo is preparing additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims - Affecting AEP System

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other unaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of two special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. Management believes the actions are without merit and intends to vigorously defend against the claims.

Nuclear Decommissioning - Affecting TCC

As discussed in the 2003 Annual Report, decommissioning costs are accrued over the service life of STP. The licenses to operate the two nuclear units at STP expire in 2027 and 2028. TCC had estimated its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

In May 2004, an updated decommissioning study was completed for STP. The study estimates TCC's share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. As discussed in Note 7, TCC is in the process of selling its ownership interest in STP to a non-affiliate, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

OPERATIONAL

Power Generation Facility - Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

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. 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. 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.

On September 5, 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo 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 OPCo's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) 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. Management believes the PPA is enforceable. The litigation is now in the discovery phase.

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

In 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In 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. The parties are currently in non-binding court-sponsored mediation.

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. The parties are currently in non-binding court-sponsored mediation.

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 these lawsuits or their impact on results of operations, cash flows and financial condition.

Texas Commercial Energy, LLP Lawsuit - Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas Retail Electric Provider (REP), filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four of its subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

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. 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 responded to that request. The case is in the initial pleading stage with our response to the complaint currently due on September 13, 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 future results of operations, financial condition or cash flows. Management cannot predict what, if any, further action, 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. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. 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. We plan to present evidence to demonstrate that we do not possess market power in geographic areas where we sell wholesale power.

6. GUARANTEES There are no material liabilities recorded for guarantees in accordance with FIN 45. 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 June 30, 2004, the maximum future payments of the LOC are $43 million which matures November 2005. 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 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 June 30, 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 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine. SWEPCo dos not have an ownership interest in 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 and during the first six months of 2004, registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary except for TCC which entered into an indemnification of $129 million relating to the sale of its generation assets on July 1, 2004 (see note 7). There are no material liabilities recorded for any indemnifications.

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 June 30, 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	$5
CSPCo	2
I&M	3
KPCo	1
OPCo	4
PSO	4
SWEPCo	4
TCC	6
TNC	3

7. DISPOSITIONS AND ASSETS HELD FOR SALE

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. As a result of the 2004 true-up proceeding, if we are unable to recover all or a portion of our requested costs (see Note 4), any unrecovered costs could have a material adverse effect on our results of operations, cash flows and possibly financial condition.

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, except in the case that our true-up proceedings, as described above, do not allow for recovery of our stranded costs.

Oklaunion Power Station

In April 2004, TCC signed an agreement to sell its 7.81 percent share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, TCC received notice from co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. The sale is currently being challenged by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that the co-owner has exceeded its legal authority and has requested that the court declare the one co-owner's exercise of its right of first refusal void. The unrelated party further argues that the second of the two co-owner's exercise of its right of first refusal is not timely and invalid. TCC expects that it will be able to resolve this legal issue and that the planned sale will close by the end of 2004.

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. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. TCC expects the sale to close before the end of 2004 subject to necessary regulatory approval.

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. The sale was completed in July 2004 for approximately $425 million, net of adjustments. The sale did not have a significant effect on TCC's results of operation during the second quarter 2004.

The assets and liabilities of the TCC plants held for sale at June 30, 2004 and December 31, 2003 are as follows:

	June 30, 2004	December 31, 2003
	(in millions)	
Assets:		
Other Current Assets	$58	$57
Property, Plant and Equipment, Net	796	797
Regulatory Assets	51	49
Decommissioning Trusts	132	125
Total Assets Held for Sale	$1,037	$1,028
Liabilities:		
Regulatory Liabilities	$9	$9
Asset Retirement Obligations	227	219
Total Liabilities Held for Sale	$236	$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 tables provide the components of AEP's net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2004 and 2003:

Three Months ended June 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
		(in millions)		
Service Cost	$21	$20	$10	$11
Interest Cost	57	59	30	33
Expected Return on Plan Assets	(73)	(80)	(20)	(17)
Amortization of Transition (Asset) Obligation	1	(2)	7	6
Amortization of Net Actuarial Loss	4	3	9	13
Net Periodic Benefit Cost (Credit)	$10	$-	$36	$46

Six Months ended June 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in millions)			
Service Cost	$43	$40	$20	$21
Interest Cost	114	117	59	65
Expected Return on Plan Assets	(146)	(159)	(41)	(32)
Amortization of Transition (Asset) Obligation	1	(4)	14	14
Amortization of Net Actuarial Loss	8	5	18	26
Net Periodic Benefit Cost (Credit)	$20	$(1)	$70	$94

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for the three and six months ended June 30, 2004 and 2003:

Three Months ended June 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in thousands)			
APCo	$313	$(1,299)	$6,430	$8,371
CSPCo	(409)	(1,350)	2,763	3,671
I&M	1,112	(201)	4,315	5,749
KPCo	143	(140)	741	1,011
OPCo	(34)	(1,656)	4,907	7,036
PSO	684	(72)	2,112	2,471
SWEPCo	888	254	2,100	2,566
TCC	728	(32)	2,536	3,237
TNC	332	153	1,070	1,469

Six Months ended June 30, 2004 and 2003:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2004	2003	2004	2003
	(in thousands)			
APCo	$635	$(2,600)	$12,860	$16,809
CSPCo	(813)	(2,700)	5,525	7,342
I&M	2,230	(404)	8,630	11,499
KPCo	287	(282)	1,481	2,021
OPCo	(62)	(3,312)	9,813	14,072
PSO	1,397	(146)	4,224	4,942
SWEPCo	1,802	508	4,200	5,132

TCC	1,494	(62)	5,072	6,475
TNC	676	304	2,140	2,937

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 issued and retired during the first six months of 2004 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
CSPCo	Installment Purchase Contracts	$43,695	Variable	2038
OPCo	Financing Obligation	6,080	5.77	2024
PSO	Installment Purchase Contracts	33,700	Variable	2014
PSO	Senior Unsecured Notes	50,000	4.70	2009
SWEPCo	Installment Purchase Contracts	53,500	Variable	2019
SWEPCo	Installment Purchase Contracts	41,135	Variable	2011
SWEPCo	Financing Obligation	14,226	5.77	2024

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements:				
APCo	First Mortgage Bonds	45,000	7.125	2024
APCo	Installment Purchase Contracts	40,000	5.45	2019
CSPCo	First Mortgage Bonds	11,000	7.60	2024
CSPCo	Installment Purchase Contracts	43,695	6.25	2020
I&M	First Mortgage Bonds	30,000	7.20	2024
I&M	First Mortgage Bonds	25,000	7.50	2024
OPCo	Installment Purchase Contracts	50,000	6.85	2022
OPCo	Notes Payable	1,500	6.27	2009
OPCo	Notes Payable	2,927	6.81	2008
OPCo	First Mortgage Bonds	10,000	7.30	2024
OPCo	Senior Unsecured Notes	140,000	7.375	2038
PSO	Notes Payable to Trust	77,320	8.00	2037
PSO	Installment Purchase Contracts	33,700	4.875	2014
SWEPCo	Installment Purchase Contracts	53,500	7.60	2019
SWEPCo	Installment Purchase Contracts	12,290	6.90	2004
SWEPCo	Installment Purchase Contracts	12,170	6.00	2008
SWEPCo	Installment Purchase Contracts	17,125	8.20	2011
SWEPCo	First Mortgage Bonds	80,000	6.875	2025
SWEPCo	First Mortgage Bonds	40,000	7.75	2004
SWEPCo	Notes Payable	3,415	4.47	2011
SWEPCo	Notes Payable	1,500	Variable	2008
TCC	First Mortgage Bonds	6,195	6.625	2005
TCC	Securitization Bonds	28,809	3.54	2005
TNC	First Mortgage Bonds	24,036	6.125	2004

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Defeasance:				
TCC	First Mortgage Bonds	$27,400 (a)	7.25	2004
TCC	First Mortgage Bonds	65,763 (a)	6.625	2005
TCC	First Mortgage Bonds	18,581 (a)	7.125	2008

(a) Trust fund assets for defeasance of First Mortgage Bonds of $103 million are included in Other Cash Deposits and $22 million in Bond Defeasance Funds in TCC's Consolidated Balance Sheets at June 30, 2004. Trust fund assets are restricted for exclusive use in retiring the First Mortgage Bonds.

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	Interest Rate	Due Date
		(in thousands)	(%)	
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). Our previous order grating borrowing authority to our utilities listed below expired on June 30 2004. Through June 30, 2004, we had not exceeded our authority under the previous order. The following are the SEC authorized limits for short-term borrowings for the domestic utility companies as of July 1, 2004:

	Authorized
	(in millions)
AEP Generating Company	$125
AEP Texas Central Company	600
AEP Texas North Company	250
Appalachian Power Company	600

Columbus Southern Power Company	150
Indiana Michigan Power Company	500
Kentucky Power Company	200
Ohio Power Company	600
Public Service Company of Oklahoma	300
Southwestern Electric Power Company	350

REGISTRANT SUBSIDIARIES' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a combined presentation of certain components of the registrant subsidiaries' 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 issued a final order in June 2004.

In April 2004, KPCo reached an agreement with interveners to settle the RTO issues in Kentucky. The KPSC approved the settlement agreement in May 2004 and the FERC approved the settlement in June 2004.

In July 2004, APCo reached an agreement with the intervenors to settle the RTO issues in Virginia. The settlement agreement is now subject to approval by the Virginia SCC.

If the Virginia settlement is approved, it should allow the AEP East companies to join PJM and address state concerns without any significant expected adverse impacts on future results of operations.

AEP West companies are members of ERCOT or SPP. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

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 six months of 2004, that should be read in order to gain a full understanding of the current litigation include disclosure related to Potential Uninsured Losses.

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 Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In 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. The parties are currently in non-binding court-sponsored mediation.

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. The parties are currently in non-binding court-sponsored mediation.

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 these lawsuits or their impact on results of operations, cash flows or financial condition.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas Retail Electric Provider (REP), filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four of its subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against TCC and TNC, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against AEP and its subsidiaries. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

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. 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 responded to that request. The case is in the initial pleading stage with our response to the complaint currently due on September 13, 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 future results of operations, financial condition or cash flows. Management cannot predict whether these governmental agencies will take further action with respect to these matters.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the Clean Air Act for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input valve, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. No action can be commenced until 60 days after the date of notice.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input valve in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, and the referenced recordkeeping and reporting requirements and heat input valve at Welsh. We are preparing additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, cash flows or financial condition.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other unaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Counsel on behalf of two special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. Management believes the actions are without merit and intends to vigorously defend against the claims.

Environmental Matters

As discussed in the 2003 Annual Report, there are emerging 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 (SO2), nitrogen oxide (NOx) 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. 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 disposal 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 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 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 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 a Clean Air Interstate Rule (CAIR) to reduce SO2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the new 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 were proposed on June 10, 2004.

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 CAIR, described above, the Federal EPA proposed that participation in the trading program under the CAIR would satisfy any applicable "Best Available Retrofit" requirements. However, the guidance preserves the ability of a state to require site-specific installation of pollution control equipment through the SIP for purposes of abating regional haze.

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. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO2 and NOx reduction requirements imposed on the same sources under the CAIR. 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 effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 tons to 34 tons by 2010 and to 15 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. We filed comments on both the initial proposal and the supplemental notice in June 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 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 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.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA is expected to file a motion to amend its complaint, and, to the extent that motion seeks to expand the scope of the pending litigation, the AEP subsidiaries will oppose that motion.

Management is unable to estimate the loss or range of loss related to any contingent liability the AEP subsidiaries might have for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If 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 other pending CAA litigation against unaffiliated utility companies referenced in the annual report, the petition for certiorari filed with the Supreme Court in the TVA litigation was denied by the Court on May 3, 2004. In addition, the United States has filed a notice of appeal with the Fourth Circuit Court of Appeals from the adverse decision in the Duke case, and a briefing order has been issued by the Court that will require briefing to be completed by late September 2004.

Clean Water Act Regulation

On July 9, 2004, the Federal EPA published in the Federal Registrar 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 estimated 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. Several states, electric utilities (including APCo) and environmental groups appealed certain aspects of the rule. Management cannot predict the outcome of the appeals. 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. There 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 July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. 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. We plan to present evidence to demonstrate that we do not possess market power in geographic areas where we sell wholesale power.

CONTROLS AND PROCEDURES

During the second quarter of 2004, management, including the principal executive officer and principal financial officer of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures relating to the recording, processing, summarization and reporting of information in the Registrants' periodic reports filed with the SEC. These disclosure controls and procedures have been designed to ensure that (a) material information relating to the Registrants is made known to the Registrants' management, including these officers, by other employees of the Registrants, 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. The Registrant's controls and procedures can only provide reasonable, not absolute, assurance that the above objectives have been met.

As of June 30, 2004, these officers concluded that the disclosure controls and procedures in place provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants 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 the Registrants' 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 second quarter of 2004 that have materially affected, or are reasonably likely to materially affect, the Registrants' 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 June 30, 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
04/01/04 - 04/30/04	-	$-	-	$-
05/01/04 - 05/31/04	5	70.00	-	-
06/01/04 - 06/30/04	3	69.00	-	-
Total	8	$69.63	-	$-

(1) TCC and OPCo repurchased an aggregate of 5 shares of its 4% cumulative preferred stock and 3 shares of its 4.5% cumulative preferred stock, respectively, in privately-negotiated transactions outside of an announced program.

Item 4. Submission of Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Columbus, Ohio, on April 27, 2004. The holders of shares entitled to vote at the meeting or their proxies cast votes at the meeting with respect to the following six matters, as indicated below:

1. Election of eleven directors to hold office until the next annual meeting and until their successors are duly elected. Each nominee for director received the votes of shareholders as follows:

Shares	No. of Shares Voted For	No. of Abstaining
E. R. Brooks	304,880,019	8,450,055
Donald M. Carlton	301,928,439	11,401,635
John P. DesBarres	304,936,922	8,393,152
Robert W. Fri	305,300,688	8,029,386
William R. Howell	305,172,590	8,157,484
Lester A. Hudson, Jr.	300,799,680	12,530,394
Leonard J. Kujawa	301,737,241	11,592,833
Michael G. Morris	300,949,642	12,380,432
Richard L. Sandor	303,225,412	10,104,662
Donald G. Smith	303,120,154	10,209,920
Kathryn D. Sullivan	302,132,773	11,197,301

2. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent auditors for 2004. The proposal was approved by a vote of the shareholders as follows:

Votes FOR
296,126,400
Votes AGAINST
15,883,072
Votes ABSTAINED
1,320,602
Broker NON-VOTES*
0

3. Shareholder proposal submitted by the International Brotherhood of Electrical Workers' Pension Benefit Fund urging the Board of Directors to seek shareholder approval of certain future severance agreements with senior executives. The proposal was approved by a vote of the shareholders as follows:

Votes FOR
149,622,711
Votes AGAINST
108,314,061
Votes ABSTAINED
5,307,905
Broker NON-VOTES*
50,085,397

4. Shareholder proposal submitted by the AFL-CIO Reserve Fund urging the Board of Directors to seek shareholder approval of certain future extraordinary pension benefits for senior executives. The proposal was disapproved by a vote of the shareholders as follows:

Votes FOR
73,773,833
Votes AGAINST
184,152,624
Votes ABSTAINED
5,318,220
Broker NON-VOTES*
50,085,397

5. Shareholder proposal submitted by the United Association S&P 500 Fund requesting the Board of Directors and its Audit Committee adopt a policy that would limit the work performed by the public accounting firm retained by the Company to "audit" and "audit-related" services. The proposal was disapproved by a vote of the shareholders as follows:

Votes FOR
36,206,757
Votes AGAINST
221,661,710

Votes ABSTAINED
5,376,210
Broker NON-VOTES*
50,085,397

6. Shareholder proposal submitted by Mr. Ronald Marsico seeking to limit the maximum amount of service by any Director, except for the Chief Executive Officer and the President, to eight terms of office. The proposal was disapproved by a vote of the shareholders as follows:

Votes FOR
21,178,705
Votes AGAINST
236,643,469
Votes ABSTAINED
5,422,499
Broker NON-VOTES*
50,085,401

*A non-vote occurs when a nominee holding shares for a beneficial owner votes on one proposal, but does not vote on another proposal because the nominee does not have discretionary voting power and has not received instructions from the beneficial owner.

APCo

The annual meeting of stockholders was held on April 27, 2004 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast FOR each of the following nine persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Jeffrey D. Cross	Robert P. Powers
Henry W. Fayne	Thomas V. Shockley, III
Thomas M. Hagan	Stephen P. Smith
Michael G. Morris	Susan Tomasky
Armando A. Pena	

TCC

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 8, 2004, the following nine persons were elected directors to hold office for one year or until their successors are elected and qualify:

Jeffrey D. Cross	Robert P. Powers
Henry W. Fayne	Thomas V. Shockley, III
Thomas M. Hagan	Stephen P. Smith
Michael G. Morris	Susan Tomasky
Armando A. Pena	

I&M

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 27, 2004, the following thirteen persons were elected directors to hold office for one year or until their successors are elected and qualify:

Karl G. Boyd	Susanne M. Moorman
John E. Ehler	Michael G. Morris
Henry W. Fayne	Robert P. Powers
Thomas M. Hagan	John R. Sampson
Patrick C. Hale	Thomas V. Shockley, III
David L. Lahrman	Susan Tomasky
Marc E. Lewis	

OPCo

The annual meeting of shareholders was held on May 4, 2004 at 1 Riverside Plaza, Columbus, Ohio. At the meeting there were 27,952,473 votes cast FOR each of the following nine persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Jeffrey D. Cross	Robert P. Powers
Henry W. Fayne	Thomas V. Shockley, III
Thomas M. Hagan	Stephen P. Smith
Michael G. Morris	Susan Tomasky
Armando A. Pena	

SWEPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 14, 2004, the following nine persons were elected directors to hold office for one year or until their successors are elected and qualify:

Jeffrey D. Cross	Robert P. Powers
Henry W. Fayne	Thomas V. Shockley, III
Thomas M. Hagan	Stephen P. Smith
Michael G. Morris	Susan Tomasky
Armando A. Pena	

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.

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 June 30, 2004.

Company Reporting	Date of Report	Item Reported	
AEP	April 27, 2004	Item 7.	Financial Statements and Exhibits
		Item 9.	Regulation FD Disclosure
AEP	April 29, 2004	Item 7.	Financial Statements and Exhibits
		Item 12.	Results of Operations and Financial Condition
PSO	June 7, 2004	Item 5.	Other Events and Regulation FD Disclosure
		Item 7.	Financial Statements and Exhibits

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: August 6, 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	6/30/04
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	26,970
Interest on Short-term Debt	2,552	3,295	2,329	1,751	1,104	982
Miscellaneous Interest Charges	869	2,523	1,059	1,084	1,772	1,946
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	$30,498
Earnings:						
Net Income Before Cumulative Effect of Accounting Change	$25,430	$20,763	$21,565	$20,567	$33,464	$34,027
Plus Federal Income Taxes	12,993	17,884	9,553	9,235	9,764	9,790
Plus State Income Taxes	2,784	2,457	489	1,627	(89)	(839)
Plus Fixed Charges (as above)	30,858	33,388	29,066	29,470	29,943	30,498
Total Earnings	$72,065	$74,492	$60,673	$60,899	$73,082	$73,476
Ratio of Earnings to Fixed Charges	2.33	2.23	2.08	2.06	2.44	2.40

"

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:

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:August 6, 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:

   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:August 6, 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 endedJune 30, 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
August 6, 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 endedJune 30, 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
August 6, 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