UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 2005**
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 Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes _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 April 29, 2005
American Electric Power Company, Inc.	384,020,319
AEP Generating Company	1,000
AEP Texas Central Company	2,211,678
AEP Texas North Company	5,488,560
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
Ohio Power Company	27,952,473
Public Service Company of Oklahoma	9,013,000
Southwestern Electric Power Company	7,536,640

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2005

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
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	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 off-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.
ARO	Asset Retirement Obligations.
CAA	The Clean Air Act.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
COLI	Corporate owned, life insurance program.
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.
ECAR	East Central Area Reliability Council.
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.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
GAAP	Generally Accepted Accounting Principles.
HPL	Houston Pipeline Company.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
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, a former AEP subsidiary.
ME SWEPCo	Mutual Energy SWEPCo L.P., a Texas retail electric provider.

MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
OATT	Open Access Transmission Tariff.
OCC	Oklahoma Corporation Commission.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
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.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.
SFAS 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 TCC.
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 Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing to be made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
TVA	Tennessee Valley Authority.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by CSPCo.

FORWARD-LOOKING INFORMATION

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

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

EXECUTIVE OVERVIEW

Utility Operations Segment Results
Net income from Utility Operations was $353 million for the first quarter of 2005, representing an increase of $49 million. This increase over first quarter 2004 was partially due to payments totaling $115 million received in March 2005 from Centrica related to the earnings sharing agreement as stipulated in the purchase and sale agreement from the sale of our Texas Retail Electric Providers (REPs) in 2002. The payments received related to 2002, 2003 and 2004. We expect to receive and recognize additional earnings sharing payments in 2006 and 2007 related to 2005 and 2006 activity, respectively. The earnings sharing payments for 2005 and 2006 are capped at $70 million and $20 million, respectively. However, all payments are contingent on the operating results of Centrica. Therefore, receipt of payments for future activity is not assured.

Additional increases in first quarter 2005 included $45 million related to regulatory assets established by our Ohio companies for fulfilling our Provider of Last Resort obligations, for which the PUCO authorized recovery in its approval of our Rate Stabilization Plans in January 2005.

Partially offsetting these two favorable items is an unfavorable variance of $50 million related to higher delivered fuel costs, as further discussed below in the "Fuel Costs" section, and $31 million related to reduced margins on transmission revenues.

Divestiture Proceeds
We sold a 98% share of our Houston Pipe Line Company (HPL) in January 2005 for approximately $1 billion. In March 2005, we used the cash proceeds to repurchase 12.5 million shares of our common stock in a share repurchase transaction at an initial share price of $34.63 per share and on April 15, 2005 we redeemed $550 million of our senior notes. These activities continue to emphasize our focus on strengthening our balance sheet and reducing debt at the parent company level.

Environmental
On March 10, 2005, the Federal EPA released the Clean Air Interstate Rule (CAIR), which further limits emissions of sulfur dioxide and nitrogen oxides and sets new limits on power plant emissions associated with soot, smog and acid rain in the eastern half of the United States. It is likely that we will add nine new flue gas desulphurization units (FGDs) and three selective catalytic reactors (SCRs) to our eastern fleet in order to meet existing requirements as well as the tighter requirements of the new rule. FGDs currently are installed and operating at four east and two west plants and are under construction at three east plants.

On March 15, 2005, the Federal EPA released its final rule on mercury emissions from power plants, which would allow a cap-and-trade system. The cap-and-trade system creates incentives for continued development and testing of promising mercury control technologies and, by making the mercury emissions a tradable commodity, the new system provides a strong motivation to make early emission reductions and for continuous improvements in control technologies. The installation of SCRs and FGDs at a facility have the co-benefit of mercury capture.

We are currently developing an estimate of additional costs to comply with the newly issued rules. Accordingly, we have not yet changed our previously announced plans related to capital investment amounts of $3.7 billion through 2010 and $5 billion through 2020. We continue to support our investment program through the use of free cash flow and rate increases and therefore, do not anticipate material incremental leveraging.

Texas Regulatory Activity

Stranded Cost Recovery
In February 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closing of the sale of TCC's ownership interest in Oklaunion. The asset sales

pending are our Oklaunion and STP interests. The sale of TCC's interest in STP should be completed in the first half of 2005, subject to obtaining the necessary regulatory approvals. There are likely to be delays in resolving rights of first refusal issues and related litigation with a third party affecting Oklaunion.

TCC Rate Case
Hearings were held on the affiliated transactions remand issue in March 2005. The PUCT deferred ruling on the allowable amount of TCC affiliate transactions. See the "Significant Matters - TCC Rate Case" section below for further discussion.

<u>Fuel Costs</u>
Market prices for coal, natural gas and oil increased dramatically during 2004. These increasing fuel costs are the result of increasing worldwide demand, supply uncertainty, and transportation constraints, as well as other market factors. We manage price and performance risk, particularly for coal, through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 50% of our fuel costs in our various jurisdictions. Additionally, about 20% of our fuel is used for off-system sales where prices we receive for our power sales should recover our cost of fuel. Accordingly, approximately 70% of fuel cost increases are recovered. The remaining 30% of our fuel costs relate to Ohio and West Virginia customers, where we do not have a fuel cost recovery mechanism. During the first quarter of 2005, higher delivered coal costs reduced gross margins by approximately $50 million. We currently have 100% and 88% of our projected coal needs committed for 2005 and 2006, respectively.

<u>New Technology Plant</u>
Our plans to construct synthetic-gas-fired plant(s) in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology continued to progress. During the first quarter of 2005, three important regulatory filings were made.

On February 10, 2005, we asked PJM to evaluate transmission interconnection feasibility for three potential sites currently under consideration for the plant(s). Those sites include Mason County, West Virginia, Meigs County, Ohio, and Lewis County, Kentucky. The filing with PJM will begin feasibility studies to determine the transmission network upgrades and estimated cost needed at each site to connect a new plant to the existing transmission grid.

On March 15, 2005, APCo notified the Public Service Commission of West Virginia of its intent to file for a Certificate of Public Convenience and Necessity, reflecting APCo's need for new generating capacity to meet the growing demand for electricity and to ensure a reliable supply of electricity for its customers.

On March 18, 2005, CSPCo and OPCo filed an application with the PUCO seeking authority to recover costs related to the construction and operation of an IGCC plant. This filing followed a suggestion by the PUCO in its January 2005 Rate Stabilization Plan order that CSPCo and OPCo proceed with this construction.

<u>Additional Information</u>
For additional information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations," including "Business Strategy," in our 2004 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

<u>Segments</u>

Our principal operating business segments and their major activities are:

- **Utility Operations:**
  - Domestic generation of electricity for sale to retail and wholesale customers.
  - Domestic electricity transmission and distribution.

- **Investments-Gas Operations** (a)
  - Gas pipeline and storage services.
  - Gas marketing and risk management activities.

- **Investments-UK Operations** (b)
  - Generation of electricity in the U.K. for sale to wholesale customers.
  - Coal procurement and transportation to our plants.

- **Investments-Other:** (c)
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

(a) LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued operations during 2003 and were sold during 2004. We sold a 98% interest in HPL during the first quarter of 2005.
(b) UK Operations were classified as discontinued operations during 2003 and were sold during the third quarter of 2004.
(c) Four independent power producers were sold during the third and fourth quarter of 2004.

AEP Consolidated Results

Our consolidated Net Income for the three-month periods ended March 31, 2005 and 2004 was as follows (Earnings and Weighted Average Shares Outstanding in millions):

	2005		2004	
	Earnings	**EPS**	**Earnings**	**EPS**
Utility Operations	$ 353	$ 0.90	$ 304	$ 0.77
Investments – Gas Operations	10	0.03	(10)	(0.03)
Investments – Other	5	0.01	4	0.01
All Other (a)	(14)	(0.04)	(9)	(0.02)
Income Before Discontinued Operations	354	0.90	289	0.73
Investments – Gas Operations	-	-	(1)	-
Investments – UK Operations	(5)	(0.01)	(12)	(0.04)
Investments – Other	6	0.01	6	0.02
Discontinued Operations, Net of Tax	1	-	(7)	(0.02)
Net Income	$ 355	$ 0.90	$ 282	$ 0.71
Weighted Average Shares Outstanding		393		395

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.

First Quarter of 2005 Compared to First Quarter of 2004

Income Before Discontinued Operations increased $65 million to $354 million in the first quarter of 2005 compared to the first quarter of 2004.

For the first quarter of 2005, our Utility Operations earnings increased $49 million from the previous year driven primarily by the Centrica earnings sharing and Ohio carrying cost accruals somewhat offset by higher fuel costs and milder weather in the winter months of 2005.

Earnings from our Gas Operations increased $20 million from the previous year reflecting favorable results for one month of HPL's operations in 2005 rather than three months in the prior year due to the sale of the HPL assets in January 2005, which resulted in decreased operations, maintenance and depreciation expenses as well as decreased interest charges.

The loss from our All Other grouping, primarily representing parent company income and expenses, increased $5 million in 2005. This increase is primarily due to lower interest income and lower guarantee fees received in the current period.

Average shares outstanding decreased to 393 million in 2005 from 395 in 2004 primarily due to the common stock share repurchase program approved by our Board of Directors in February 2005.

Our results of operations by operating segment are discussed below.

Utility Operations

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(in millions)	
Revenues	$ 2,614	$ 2,602
Fuel and Purchased Power	905	779
Gross Margin	1,709	1,823
Depreciation and Amortization	318	310
Other Operating Expenses	871	888
Operating Income	520	625
Other Income (Expense), Net	148	9
Interest Expenses and Preferred Stock Dividend Requirements	144	166
Income Taxes	171	164
Income Before Discontinued Operations	$ 353	$ 304

Summary of Selected Sales Data
For Utility Operations
For the Three Months Ended March 31, 2005 and 2004

	2005	2004
Energy Summary	(in millions of KWH)	
Retail:		
Residential	13,224	13,427
Commercial	8,732	8,779
Industrial	12,774	12,273
Miscellaneous	645	743
Subtotal	35,375	35,222
Texas Retail and Other	228	224
Total	35,603	35,446
Wholesale	12,635	13,851
Texas Wires Delivery	5,519	5,490

Weather Summary	2005	2004
	(in degree days)	
Eastern Region		
Actual – Heating	1,774	1,864
Normal – Heating (a)	1,811	1,806
Actual – Cooling	-	3
Normal – Cooling (a)	3	3
Western Region (b)		
Actual – Heating	769	883
Normal – Heating (a)	973	978
Actual – Cooling	20	30
Normal – Cooling (a)	18	17

(a) Normal Heating/Cooling represents the 30-year average of degree days.
(b) Western Region statistics represent PSO/SWEPCo customer base only.

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005
Income Before Discontinued Operations
(in millions)

First Quarter of 2004		$ 304
Changes in Gross Margin:		
Retail Margins	(60)	
Texas Supply	(20)	
Transmission Revenues	(31)	
Off-system Sales	(7)	
Other Revenues	4	
		(114)
Changes in Operating Expenses And Other:		
Maintenance and Other Operation	21	
Depreciation and Amortization	(8)	
Taxes Other Than Income Taxes	(4)	
Other Income (Expense), Net	139	
Interest Expenses	22	
		170
Income Taxes		(7)
First Quarter of 2005		$ 353

Income from Utility Operations increased $49 million to $353 million in 2005. The key drivers of the increase were a $139 million increase in other income (expense), net and a $31 million net decrease in operating expenses and other partially offset by a $114 million decrease in gross margin and a $7 million increase in income tax expense.

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

- Overall retail margins in our utility business were $60 million lower than last year. The primary driver of this decrease was higher delivered fuel costs of approximately $50 million, of which $25 million relates to our Ohio jurisdiction, $16 million relates to APCo and $6 million relates to I&M.
- Our Texas supply business had a $20 million decrease in gross margin as a result of decreased generation due to the sale of a majority of our Texas generation assets in the third quarter of 2004.
- Margins from transmission revenues decreased $31 million primarily due to the loss of through and out rates as mandated by the FERC.
- Margins from off-system sales for 2005 were $7 million lower than 2004 primarily due to lower optimization activity of $31 million partially offset by a $24 million increase in revenues due to a 5% increase in sales volumes.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses decreased $21 million. Overall, the decrease is due to timing and different spending patterns experienced in the first quarter of 2005 as compared to the same period in 2004. Additionally, benefit expenses were lower by $23 million primarily due to the cancellation of our corporate-owned life insurance (COLI) policies in 2005. These favorable variances were partially offset by storm expenses of $19 million related to a major ice storm in January 2005, primarily in our Indiana and Ohio jurisdictions.
- Other Income (Expense), Net increased $139 million primarily due to the following:
    - $112 million related to the $115 million payment received in March 2005 for the Centrica earnings sharing, which represents receipt of revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase and sale agreement from the sale of our REPs in 2002. Agreement was reached with Centrica in March 2005 resolving disputes on how such amounts are to be calculated.
    - $26 million related to the accrual of carrying costs on environmental and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
- Interest Expenses decreased $22 million due to the refinancing of higher coupon debt and the retirement of debt in 2004 and in the first quarter of 2005.

See "Income Taxes" section below for discussion of fluctuations related to income taxes.

Investments-Gas Operations

First Quarter of 2005 Compared to First Quarter of 2004

Our $10 million net income from Gas Operations before discontinued operations compares with a $10 million loss recorded in the first quarter of 2004. Due to the sale of the HPL assets in January 2005, current year results include only one month of HPL's operations compared to three months of HPL's operations in the prior year. Approximately $14 million of the $20 million variance relates to a decrease in operation, maintenance and depreciation expenses and $5 million relates to a decrease in interest charges.

Investments – UK Operations

First Quarter of 2005 Compared to First Quarter of 2004

Losses from our Investments – UK Operations segment (all classified as Discontinued Operations) were $5 million in 2005 as compared to $12 million in 2004 due to the sale of substantially all operations and assets within our Investments – UK Operations segment in July 2004. The current period amount represents purchase price true-up adjustments made during the first quarter of 2005 related to the sale in 2004.

Investments – Other

First Quarter of 2005 Compared to First Quarter of 2004

Income before discontinued operations from our Investments – Other segment increased by $1 million in 2005 primarily due to the following:

- A $5 million increase at CSW Energy Services related to a current year gain due to a working capital true-up of the Numanco sale that occurred in November 2004 and a release of product liability and litigation reserves related to our Total Electric Vehicle investment due to the resolution of all open litigation as of March 31, 2005.
- A $3 million increase at AEP Communications due to debt being moved to the parent in October 2004.
- A $3 million increase at AEP Investments due to the investment write-down of PHPK Technologies, Inc. in 2004 of $1 million and favorable earnings from Pac Hydro of $2 million in 2005.
- A $3 million increase at CSW International related to tax reserve adjustments in March 2005.
- A $13 million decrease at AEP Resources related to a $2 million favorable judgment on an Australian tax issue received in 2004, a $4 million entry in 2004 related to capitalized fuel during construction of the Dow Plant, $3 million of losses related to the Dow plant in 2005 and a tax adjustment of $3 million booked in 2005.
- A $3 million decrease at our IPPs resulting from the sale of four of our IPPs in mid-2004.

All Other

First Quarter of 2005 Compared to First Quarter of 2004

Our parent company's loss for the first quarter of 2005 increased $5 million in comparison to the first quarter of 2004 due to lower interest income of $2 million and lower guarantee fees received of $1 million.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 32.7% and 35.9%, 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 temporary differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences including COLI and lower state income taxes.

FINANCIAL CONDITION

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

Capitalization ($ in millions)

	March 31, 2005		December 31, 2004	
Common Shareholders' Equity	$ 8,268	39.9 %	$ 8,515	40.6 %
Cumulative Preferred Stock	61	0.3	61	0.3
Cumulative Preferred Stock (Subject to Mandatory Redemption)	-	-	66	0.3
Long-term Debt, including amounts due within one year	12,359	59.7	12,287	58.7
Short-term Debt	19	0.1	23	0.1
Total Capitalization	$ 20,707	100.0 %	$ 20,952	100.0 %

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share. The 12.5 million shares repurchased under the program are subject to a future contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period. Based on this adjustment, an asset of $2 million is reflected in Accounts Receivable on our Consolidated Balance Sheets as of March 31, 2005 due to the fact that the actual stock purchase prices were less than our initial payment.

As a consequence of the capital changes during the first quarter of 2005, our ratio of debt to total capital increased from 59.1% to 59.8% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

In April 2005, we reduced our ratio of debt to total capital through the redemption of $550 million of parent company senior notes.

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 March 31, 2005, of approximately $4 billion as illustrated in the table below.

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,000	May 2007
Revolving Credit Facility	1,500	March 2010
Letter of Credit Facility	200	September 2006
Total	2,700	
Cash and Cash Equivalents	1,261	
Total Liquidity Sources	3,961	
Less: AEP Commercial Paper Outstanding	-(a)	
Letters of Credit Outstanding	50	
Net Available Liquidity at March 31, 2005	$ 3,911	

(a) Amount does not include JMG commercial paper outstanding in the amount of $19 million. This commercial paper is specifically associated with the Gavin scrubber and does not reduce AEP's available liquidity. The JMG commercial paper is supported by a separate letter of credit facility not included above.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At March 31, 2005, this percentage was 55%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 2005, we complied with the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the 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 the $1.5 billion revolving credit facility, which matures in March 2010, we may borrow despite a material adverse change if our ratings are BBB (or better) from Standard and Poor's (S&P), and Baa2 (or better) from Moody's at any time during the facility's term.

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 March 31, 2005, we were in compliance with this order.

Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC or state commission authorized limits. At March 31, 2005, we had not exceeded the SEC or state commission authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2005 and AEP, Inc. is currently on a "positive" outlook by Moody's.

Our current ratings by the major agencies are as follows:

	Moody's	S&P	Fitch
Short-term Debt	P-3	A-2	F-2
Senior Unsecured Debt	Baa3	BBB	BBB

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

Cash Flow

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

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(in millions)	
Cash and cash equivalents at beginning of period	$ 320	$ 778
Cash flows from (used for):		
Operating activities	673	897
Investing activities	788	(186)
Financing activities	(520)	(576)
Net increase in cash and cash equivalents	941	135
Cash and cash equivalents at end of period	$ 1,261	$ 913
Other temporary cash investments	$ 181	$ 340

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 Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of our other subsidiaries that are not participants in the Nonutility Money Pool. As of March 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. At March 31, 2005, we had no outstanding short-term borrowings supported by the revolving credit facilities. JMG had commercial paper outstanding in the amount of $19 million. This commercial paper is specifically associated with the Gavin scrubber and is not supported by our credit facilities. The maximum amount of commercial paper outstanding during the quarter ended

March 31, 2005 was $25 million. The weighted-average interest rate for our commercial paper during the first quarter of 2005 was 2.59%.

We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding alternatives are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements.

In addition to our cash and cash equivalents we have other temporary cash investments on hand that factor in managing and maintaining our liquidity.

Operating Activities

	Three Months Ended March 31,	
	2005	**2004**
	(in millions)	
Net Income	$ 355	$ 282
Plus: Loss From Discontinued Operations	(1)	7
Income from Continuing Operations	354	289
Noncash Items Included in Earnings	243	222
Changes in Assets and Liabilities	76	386
Net Cash Flows From Operating Activities	$ 673	$ 897

The key drivers of the decrease in cash from operations for the first quarter of 2005 are the pension trust contribution of $102 million and the gain on sale of assets of $115 million, $112 million of which relates to the sale of our Texas REPs to Centrica.

<u>2005 Operating Cash Flow</u>

Our net cash flows from operating activities were $673 million for the first quarter of 2005. We produced income from continuing operations of $354 million during the period. Income from continuing operations for the period included noncash expense items of $318 million for depreciation, amortization, accretion and deferred taxes. In addition, there is a current period favorable impact for a net $27 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. We made a $102 million contribution to our pension trust fund. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a decrease in the balance of fuel, materials and supplies of $64 million primarily due to reduced gas inventory associated with the sale of HPL and an increase in the balance of accrued taxes of $245 million. Accrued taxes increased because our consolidated tax group was not required to make an estimated payment during the first quarter of 2005.

<u>2004 Operating Cash Flow</u>

Our net cash flows from operating activities were $897 million for the first quarter of 2004. We produced income from continuing operations of $289 million during the period. Income from continuing operations for the period included noncash items of $374 million for depreciation, amortization, accretion and deferred taxes. There was a current period unfavorable impact for a net $59 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 most significant changes in other activity in the asset and liability accounts are an increase in accrued taxes of $189 million and net changes in accounts receivable and accounts payable of $88 million.

Investing Activities

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Construction Expenditures	$ (465)	$ (305)
Change in Other Temporary Cash Investments, Net	94	64
Proceeds from Sales of Assets	1,157	40
Other	2	15
Net Cash Flows From (Used for) Investing Activities	$ 788	$ (186)

Our cash flows from investing activities were $788 million in 2005 primarily due to proceeds from the sale of HPL in 2005. We used the cash from asset sales to repurchase common stock. Our construction expenditures include environmental, transmission and distribution investments as we had planned. Our remaining construction expenditures for 2005 are estimated to be approximately $2.2 billion.

Our cash flows used for investing activities were $186 million in 2004 primarily due to construction expenditures.

Financing Activities

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Issuances of Common Stock	$ 17	$ 10
Repurchase of Common Stock	(434)	-
Issuances/Retirements of Debt, net	101	(444)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid	(138)	(138)
Net Cash Flows Used for Financing Activities	$ (520)	$ (576)

Our cash flows used for financing activities in 2005 were $520 million. During the first quarter of 2005, we repurchased common stock using the proceeds from the sale of HPL. Our subsidiaries retired $66 million of cumulative preferred stock. See Note 10 for a complete discussion of debt issuances and retirements.

Our cash flows used for financing activities were $576 million in 2004. During the first quarter of 2004, we retired debt using cash from operating activities. We retired approximately $414 million of long-term debt, excluding $25 million related to an asset sale, and decreased our short-term debt by $103 million. We also issued approximately $73 million of long-term debt.

Off-balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our 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 we enter in the normal course of business. Our off-balance sheet arrangements have not changed significantly from year-end. For complete information on each of these off-balance sheet arrangements see the "Minority Interest and Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 Annual Report.

SIGNIFICANT MATTERS

Texas Regulatory Activity

Texas Restructuring

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items in TCC's future true-up filing. TCC has asked permission from the PUCT to file its True-up Proceeding after the sales of its interest in STP have been concluded. If the request is approved, it is anticipated that TCC's True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of its net regulatory asset of $1.6 billion for its net stranded cost and other true-up items which it believes the Texas Restructuring Legislation allows.

TCC continues to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 further clarifying how the amounts are to be calculated. This resulted in a reduction in TCC's accrued carrying costs based on the methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on TCC's net stranded cost and other true-up items retroactive to January 1, 2004. In the first quarter of 2005, TCC accrued carrying costs of $21 million, which was more than offset by an adverse adjustment of $27 million based on this order. The net reduction of $6 million in carrying costs is included in Other Income in the first quarter of 2005 on the accompanying Consolidated Statements of Income.

As of March 31, 2005, TCC has computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying cost, of $154 million, will be recognized in income as collected.

When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated transmission and distribution (T&D) rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in TCC's future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

TCC Rate Case

TCC has an on-going T&D rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If TCC were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing TCC's rates could have an adverse effect on future results of operations and cash flows.

Ohio Regulatory Activity

Ohio Restructuring

In January 26, 2005 the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter of 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

IGCC Power Plant

On March 18, 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $18 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover approximately $237 million in construction financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their Rate Stabilization Plans. In Phase 3, which begins when the plant enters commercial operation, projected to be in mid-2010, the Ohio companies would recover the projected $1.0 billion cost of the plant and a return on the unrecovered cost over its operating life along with fuel, replacement power and operation and maintenance costs.

Oklahoma Regulatory Activity

PSO Rate Review

PSO is involved in a commission staff-initiated rate review before the OCC seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

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 submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation 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.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, PSO estimates that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power for 2003. Management is unable to predict if the OCC will order a prudence review of PSO's fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005. SECA billings by PJM crediting AEP for their SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Litigation

We continue to be involved in various litigation described in the "Significant Factors – Litigation" section of Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report. The 2004 Annual Report should be read in conjunction with this report in order to understand other litigation that did not have significant changes in status since the issuance of our 2004 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition. Other matters described in the 2004 Annual Report that did not have significant changes during the first quarter of 2005, that should be read in order to gain a full understanding of our current litigation include: (1) Bank of Montreal Claim, (2) Coal Transportation Dispute, (3) Shareholders' Litigation 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.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate 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. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. On April 6, 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In January 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of the 98% interest in HPL against any damages resulting from the BOA litigation up to the purchase price. The recognition and the amount of the gain is dependent upon the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding 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 nonbinding 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. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but were subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine. We will continue to defend vigorously each case where an AEP company is a defendant.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, certain nonaffiliated 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, 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.

In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint, which the Court denied in September 2004. Plaintiffs have filed a Motion for Class Certification. The defendants, including AEP and AEPES, filed their opposition to class certification on April 8, 2005. Briefing on the issue of class certification is expected to be completed in the second quarter of 2005. Discovery is continuing in the case with a discovery cut-off date of June 30, 2005. We intend to defend vigorously against these claims.

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 CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, 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. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May 2005.

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 value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 2005, TCEQ issued an Executive Director’s Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo’s permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director’s Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

TEM Litigation

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We 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's 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 (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA.

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 these electric power products 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 the 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.

A bench trial was conducted in March and April 2005.

Environmental Matters

As discussed in our 2004 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:

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

This discussion updates certain events occurring in 2005. You should also read the "Significant Factors – Environmental Matters" section within Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report for a description of all environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) the Comprehensive Environmental Response Compensation and Liability Act (Superfund) and state remediation, (4) global climate change, (5) carbon dioxide public nuisance claims, (6) costs for spent nuclear fuel disposal and decommissioning, and (7) Clean Water Act regulation.

Future Reduction Requirements for SO_2, NO_x and Mercury

Regulatory Emissions Reductions

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

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the Eastern 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.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

On March 14, 2005, the Administrator of the Federal EPA signed the final CAIR. The rule is slightly revised from the proposed version released in January 2004, and includes both a seasonal and annual NO_x control program as well as an annual SO_2 control program. All of the states in which our generating facilities are located will be subject to the regional and annual NO_x control programs and the annual SO_2 control program, except for Texas, Oklahoma and Arkansas. Texas will be subject to the annual programs only. Arkansas will be subject to the seasonal NO_x control program only. Oklahoma is not affected by CAIR. In addition, the compliance deadline for Phase I for the NO_x control program has been accelerated to 2009, and will replace any obligations imposed by the NO_x State Implementation Plan (SIP) Call in 2009.

On March 15, 2005, the Administrator of the Federal EPA signed a final Clean Air Mercury Rule (CAMR) that will 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. The final CAMR imposes a national cap on mercury emissions from coal-fired power plants of 38 tons by 2010 and 15 tons by 2018.

The changes in the Federal EPA's final CAIR and CAMR have not caused us to revise our estimates of the capital investments necessary to achieve compliance with these requirements. However, final rules give states substantial discretion in developing their rules to implement these cap-and-trade programs, and states 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. If states elect not to participate in the federal cap-and-trade programs, or elect to impose additional requirements on individual units that are already subject to CAIR and/or the CAMR, our costs could increase significantly. The cost of compliance could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review Litigation

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

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated 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 occurred 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 filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. The Federal EPA and the states each have filed an additional complaint alleging violations of the new source review requirements at units at the Amos and Conesville plants that were not allowed to be added to the pending case. These separate complaints have been assigned to the same judge in the Southern District Court.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the U.S. District Court for the Southern District of Ohio alleging that violations of the prevention of significant deterioration and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against the Tennessee Valley Authority (TVA), the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. 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.

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.

Emergency Release Reporting

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances that cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCo's Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, 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.

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

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
Three Months Ended March 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	$ 265
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(37)	(5)	12	(30)
Fair Value of New Contracts When Entered During the Period (b)	1	-	-	1
Net Option Premiums Paid/(Received) (c)	-	-	-	-
Change in Fair Value Due to Valuation Methodology Changes	-	-	-	-
Changes in Fair Value of Risk Management Contracts (d)	29	(5)	-	24
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(8)	-	-	(8)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2005	$ 262	$ (10)	$ -	252
Net Cash Flow and Fair Value Hedge Contracts (f)				(61)
Ending Net Risk Management Assets at March 31, 2005				$ 191

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered in 2005.

(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) "Changes 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 assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed in detail within the following pages.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of March 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Current Assets	$ 545	$ 291	$ 836
Noncurrent Assets	497	146	643
Total Assets	1,042	437	1,479
Current Liabilities	(480)	(286)	(766)
Noncurrent Liabilities	(300)	(161)	(461)
Total Liabilities	(780)	(447)	(1,227)
Total Net Assets (Liabilities), excluding Hedges	$ 262	$ (10)	$ 252

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of March 31, 2005
(in millions)

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 836	$ 29	$ 865
Noncurrent Assets	643	3	646
Total MTM Derivative Contract Assets	1,479	32	1,511
Current Liabilities	(766)	(84)	(850)
Noncurrent Liabilities	(461)	(9)	(470)
Total MTM Derivative Contract Liabilities	(1,227)	(93)	(1,320)
Total MTM Derivative Contract Net Assets	$ 252	$ (61)	$ 191

(a) Does not include Cash Flow and Fair Value Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

<u>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)</u>

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

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

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

	Remainder 2005	2006	2007	2008	2009	After 2009	Total (c)
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (67)	$ 18	$ 22	$ -	$ -	$ -	$ (27)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	131	63	46	21	-	-	261
Prices Based on Models and Other Valuation Methods (b)	(2)	(36)	(13)	20	31	28	28
Total	$ 62	$ 45	$ 55	$ 41	$ 31	$ 28	$ 262
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 34	$ (7)	$ 4	$ -	$ -	$ -	$ 31
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(21)	(3)	-	-	-	-	(24)
Prices Based on Models and Other Valuation Methods (b)	(3)	(3)	(3)	(2)	(4)	(2)	(17)
Total	$ 10	$ (13)	$ 1	$ (2)	$ (4)	$ (2)	$ (10)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ (33)	$ 11	$ 26	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources – OTC Broker Quotes (a)	110	60	46	21	-	-	237
Prices Based on Models and Other Valuation Methods (b)	(5)	(39)	(16)	18	27	26	11
Total	$ 72	$ 32	$ 56	$ 39	$ 27	$ 26	$ 252

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers (OTC), 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 is limited, such valuations are classified as modeled.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

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

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

Commodity	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Gas East – Northeast, Mid-continent, Gulf Coast, Texas	24
	Swaps	Gas West – Rocky Mountains, West Coast	24
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	36
	Physical Forwards	Power East – Cinergy	21
	Physical Forwards	Power East – PJM West	33
	Physical Forwards	Power East – AEP Dayton (PJM)	21
	Physical Forwards	Power East – NEPOOL	21
	Physical Forwards	Power East – NYPP	33
	Physical Forwards	Power East – ERCOT	48
	Physical Forwards	Power East – Com Ed	21
	Physical Forwards	Power West – Palo Verde, North Path 15, South Path 15, MidColumbia, Mead	45
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO_2, NO_x	45
Coal	Physical Forwards	PRB, NYMEX, CSX	21

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

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

The tables below provide detail on effective cash flow hedges under SFAS 133 included in our Balance Sheets. The data in the first table indicates the magnitude of SFAS 133 hedges that 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, 2004 to March 31, 2005.

Information on energy commodity risk management activities is presented separately from interest rate risk management activities. In accordance with GAAP, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss)
On the Balance Sheet as of March 31, 2005
(in millions)

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ (36)	$ (34)
Interest Rate	(15)	(3)
Total	$ (51)	$ (37)

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2005
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value (c)	(34)	8	(26)
Reclassifications from AOCI to Net Income (d)	(25)	-	(25)
Ending Balance, March 31, 2005	$ (36)	$ (15)	$ (51)

(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 during the reporting period that are not yet settled at March 31, 2005. 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.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's, S&P and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. Our analysis, in conjunction with the rating agencies' information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At March 31, 2005, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 17.6%, expressed in terms of net MTM assets and net receivables. As of March 31, 2005, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 781	$ 191	$ 590	1	$ 97
Split Rating	18	7	11	2	11
Noninvestment Grade	269	143	126	3	93
No External Ratings:					
Internal Investment Grade	44	-	44	2	32
Internal Noninvestment Grade	14	3	11	2	11
Total	$ 1,126	$ 344	$ 782	10	$ 244

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, 2007. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. “Estimated Plant Output Hedged” represents the portion of MWHs of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of March 31, 2005

	Remainder 2005	2006	2007
Estimated Plant Output Hedged	89%	87%	88%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

VaR Model

Three Months Ended March 31, 2005 (in millions)				Twelve Months Ended December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$5	$2	$1	$3	$19	$5	$1

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

CCRO VaR Metrics
(in millions)

	March 31, 2005	Average for Year-to-Date 2005	High for Year-to-Date 2005	Low for Year-to-Date 2005
95% Confidence Level, Ten-Day Holding Period	$ 8	$ 9	$ 17	$ 5
99% Confidence Level, One-Day Holding Period	$ 3	$ 4	$ 7	$ 2

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 $653 million at March 31, 2005 and $601 million at December 31, 2004. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or consolidated financial position.

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 emissions. 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 INCOME
For the Three Months Ended March 31, 2005 and 2004
(in millions, except per-share amounts)
(Unaudited)

	2005	2004
REVENUES		
Utility Operations	$ 2,537	$ 2,581
Gas Operations	357	652
Other	89	131
TOTAL	2,983	3,364
EXPENSES		
Fuel for Electric Generation	771	694
Purchased Electricity for Resale	130	83
Purchased Gas for Resale	249	585
Maintenance and Other Operation	790	864
Depreciation and Amortization	327	319
Taxes Other Than Income Taxes	188	193
TOTAL	2,455	2,738
OPERATING INCOME	528	626
Other Income	239	62
Other Expense	(66)	(36)
INTEREST AND OTHER CHARGES		
Interest Expense	173	199
Preferred Stock Dividend Requirements of Subsidiaries	2	2
TOTAL	175	201
INCOME BEFORE INCOME TAXES	526	451
Income Taxes	172	162
INCOME BEFORE DISCONTINUED OPERATIONS	354	289
DISCONTINUED OPERATIONS, Net of Tax	1	(7)
NET INCOME	$ 355	$ 282
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	393	395
EARNINGS PER SHARE		
Income Before Discontinued Operations	$ 0.90	$ 0.73
Discontinued Operations	-	(0.02)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$ 0.90	$ 0.71
CASH DIVIDENDS PAID PER SHARE	$ 0.35	$ 0.35

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(in millions)
(Unaudited)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,261	$ 320
Other Temporary Cash Investments	181	275
Accounts Receivable:		
Customers	847	930
Accrued Unbilled Revenues	256	592
Miscellaneous	65	79
Allowance for Uncollectible Accounts	(43)	(77)
Total Receivables	1,125	1,524
Fuel, Materials and Supplies	636	852
Risk Management Assets	865	737
Margin Deposits	178	113
Other	157	200
TOTAL	4,403	4,021
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,019	15,969
Transmission	6,310	6,293
Distribution	10,378	10,280
Other (including gas, coal mining and nuclear fuel)	3,152	3,585
Construction Work in Progress	1,329	1,159
Total	37,188	37,286
Accumulated Depreciation and Amortization	14,589	14,485
TOTAL - NET	22,599	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,653	3,601
Securitized Transition Assets	632	642
Spent Nuclear Fuel and Decommissioning Trusts	1,080	1,053
Investments in Power and Distribution Projects	136	154
Goodwill	76	76
Long-term Risk Management Assets	646	470
Prepaid Pension Obligations	385	386
Other	851	831
TOTAL	7,459	7,213
Assets Held for Sale	636	628
TOTAL ASSETS	$ 35,097	$ 34,663

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 876	$ 1,051
Short-term Debt	19	23
Long-term Debt Due Within One Year (a)	1,685	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	850	608
Accrued Taxes	865	611
Accrued Interest	171	180
Customer Deposits	469	414
Other	597	775
TOTAL	5,532	5,007
NONCURRENT LIABILITIES		
Long-term Debt (a)	10,674	11,008
Long-term Risk Management Liabilities	470	329
Deferred Income Taxes	4,774	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,616	2,540
Asset Retirement Obligations	841	827
Employee Benefits and Pension Obligations	632	730
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	164	166
Deferred Credits and Other	810	411
TOTAL	20,981	20,830
Liabilities Held for Sale	255	250
TOTAL LIABILITIES	26,768	26,087
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		
2005 / 2004		
Shares Authorized 600,000,000 / 600,000,000		
Shares Issued 405,433,490 / 404,858,145		
(21,499,992 and 8,999,992 shares were held in treasury at March 31, 2005 and December 31, 2004, respectively)	2,635	2,632
Paid-in Capital	3,786	4,203
Retained Earnings	2,241	2,024
Accumulated Other Comprehensive Income (Loss)	(394)	(344)
TOTAL	8,268	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 35,097	$ 34,663

(a) See Accompanying Schedule.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(in millions)
(Unaudited)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 355	$ 282
Plus: (Income) Loss from Discontinued Operations	(1)	7
Income from Continuing Operations	354	289
Adjustments for Noncash Items:		
Depreciation and Amortization	327	319
Accretion of Asset Retirement Obligations	18	15
Deferred Income Taxes	(19)	49
Deferred Investment Tax Credits	(8)	(9)
Carrying Costs	(20)	-
Amortization of Deferred Property Taxes	(82)	(93)
Mark-to-Market of Risk Management Contracts	27	(59)
Pension Contributions	(102)	-
Over/Under Fuel Recovery	52	30
Gain on Sales of Assets	(115)	(1)
Change in Other Noncurrent Assets	(66)	2
Change in Other Noncurrent Liabilities	(64)	10
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	104	183
Fuel, Materials and Supplies	64	65
Accounts Payable	39	(95)
Taxes Accrued	245	189
Customer Deposits	55	43
Interest Accrued	(9)	(10)
Other Current Assets	(8)	5
Other Current Liabilities	(119)	(35)
Net Cash Flows From Operating Activities	673	897
INVESTING ACTIVITIES		
Construction Expenditures	(465)	(305)
Change in Other Temporary Cash Investments, Net	94	64
Investment in Discontinued Operations, Net	-	7
Proceeds from Sale of Assets	1,157	40
Other	2	8
Net Cash Flows From (Used For) Investing Activities	788	(186)
FINANCING ACTIVITIES		
Issuance of Common Stock	17	10
Repurchase of Common Stock	(434)	-
Issuance of Long-term Debt	580	73
Change in Short-term Debt, Net	31	(103)
Retirement of Long-term Debt	(510)	(414)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(138)	(138)
Net Cash Flows Used For Financing Activities	(520)	(576)
Net Increase in Cash and Cash Equivalents	941	135
Cash and Cash Equivalents at Beginning of Period	320	778
Cash and Cash Equivalents at End of Period	$ 1,261	$ 913
Net Increase in Cash and Cash Equivalents from Discontinued Operations	$ -	$ 24
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	13
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ 37

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest, net of capitalized amounts, was $170 million and $198 million in 2005 and 2004, respectively. Cash received for income taxes was $57 million in both 2005 and 2004. Noncash acquisitions under capital leases were $9 million and $4 million in 2005 and 2004, respectively.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(in millions)
(Unaudited)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	4	6			10
Common Stock Dividends				(138)		(138)
TOTAL						7,746
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					8	8
Cash Flow Hedges, Net of Tax of $12					22	22
Minimum Pension Liability, Net of Tax of $10					17	17
NET INCOME				282		282
TOTAL COMPREHENSIVE INCOME						329
MARCH 31, 2004	405	$ 2,630	$ 4,190	$ 1,634	$ (379)	$ 8,075
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515
Issuance of Common Stock		3	14			17
Common Stock Dividends				(138)		(138)
Repurchase of Common Stock			(434)			(434)
Other			3			3
TOTAL						7,963
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					1	1
Cash Flow Hedges, Net of Tax of $28					(51)	(51)
NET INCOME				355		355
TOTAL COMPREHENSIVE INCOME						305
MARCH 31, 2005	405	$ 2,635	$ 3,786	$ 2,241	$ (394)	$ 8,268

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in millions)	
First Mortgage Bonds	$ 417	$ 417
Defeased TCC First Mortgage Bonds (a)	84	84
Installment Purchase Contracts	1,935	1,773
Notes Payable	935	939
Senior Unsecured Notes	7,667	7,717
Securitization Bonds	669	698
Notes Payable to Trust	113	113
Equity Unit Senior Notes	345	345
Long-term DOE Obligation (b)	230	229
Other Long-term Debt	8	14
Equity Unit Contract Adjustment Payments	7	9
Unamortized Discount (net)	(51)	(51)
TOTAL LONG-TERM DEBT OUTSTANDING	12,359	12,287
Less Portion Due Within One Year	1,685	1,279
TOTAL LONG-TERM PORTION	$ 10,674	$ 11,008

(a) On May 7, 2004, we deposited cash and treasury securities of $125 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $70 and $72 million are included in Other Temporary Cash Investments at March 31, 2005 and December 31, 2004, respectively, and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at both March 31, 2005 and December 31, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on 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 $261 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Consolidated Balance Sheets at March 31, 2005 and December 31, 2004, respectively.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2004 Annual Report as incorporated in and filed with our 2004 Form 10-K.

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

Other Income and Other Expense

The following table provides the components of Other Income and Other Expense as presented in our Consolidated Statements of Income:

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(in millions)	
Other Income:		
Interest and Dividend Income	$ 11	$ 6
Equity Earnings	5	7
Nonutility Revenue	63	29
Gain on Sale of Texas REPs	112	-
Carrying Charges	20	2
Other	28	18
Total Other Income	$ 239	$ 62
Other Expense:		
Nonutility Expense	$ 57	$ 26
Other	9	10
Total Other Expense	$ 66	$ 36

Components of Accumulated Other Comprehensive Income (Loss)

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

Components	March 31, 2005	December 31, 2004
	(in millions)	
Foreign Currency Translation Adjustments, net of tax	$ 7	$ 6
Securities Available for Sale, net of tax	(1)	(1)
Cash Flow Hedges, net of tax	(51)	-
Minimum Pension Liability, net of tax	(349)	(349)
Total	$ (394)	$ (344)

At March 31, 2005, we expect to reclassify approximately $37 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. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations. At March 31, 2005, 21 months is the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows for forecasted transactions.

Accounting for Asset Retirement Obligations

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

	Nuclear Decommissioning	Ash Ponds	Wind Mills and Mining Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2005 Including Held for Sale	$ 960	$ 84	$ 32	$ 1,076
Accretion Expense	16	2	-	18
Asset Retirement Obligation Liability at March 31, 2005 Including Held for Sale	976	86	32	1,094
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project (a)	(253)	-	-	(253)
Asset Retirement Obligation Liability at March 31, 2005	$ 723	$ 86	$ 32	$ 841

(a) We have signed an agreement to sell TCC's share of South Texas Project (see "Texas Plants-South Texas Project" section of Note 7).

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

At March 31, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $962 million and $934 million, respectively, of which $819 million and $791 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 South Texas Project totaling $143 million at March 31, 2005 and December 31, 2004, 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.

In connection with preparation of these financial statements, we concluded that it was appropriate to classify our auction rate securities as other temporary cash investments. Previously, such investments had been classified as cash and cash equivalents. Accordingly, we have revised the classification to exclude from cash and cash equivalents $103 million at December 31, 2004, and to include such amounts as other temporary cash investments. There were no auction rate securities held at March 31, 2005. At December 31, 2003, auction rate securities approximated $200 million. In addition, the following represents supplemental disclosures to the Statements of Cash Flows for the three-month periods ended March 31, 2005 and 2004:

	2005	2004
	(in millions)	
Purchases of Auction Rate Securities	$ 785	$ 23
Proceeds from Sale of Auction Rate Securities	888	23

These revisions had no impact on previously reported results of operations, operating cash flows or working capital of the Company.

Prior Period Adjustment

As disclosed in our 2004 Annual Report, in the second quarter of 2004 we implemented FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 (FSP FAS 106-2), retroactive to January 1, 2004. The effect of implementing FSP FAS 106-2 on the first quarter of 2004 is as follows:

Three Months Ended March 31, 2004	**Net Income (in Millions)**		**Earnings Per Share**	
Originally Reported	$	278	$	0.70
Effect of Medicare Subsidy		4		0.01
Restated	$	282	$	0.71

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2005 that we have determined relate to our operations.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25. The statement is effective as of the first annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially adopting the statement.

We will implement SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. We will apply the principles of SAB 107 in conjunction with our adoption of SFAS 123R.

FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We will implement FIN 47 during the fourth quarter for the fiscal year ending December 31, 2005. Implementation will require an adjustment for the cumulative effect for the nonregulated operations of initially adopting FIN 47 to be recorded as a change in accounting principle, disclosure of pro forma liabilities and asset retirement obligations, and other additional disclosures. We have not completed our evaluation of any potential impact to our results of operations or financial condition.

EITF Issue 03-13 "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations"

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. During the first quarter of 2005, we applied this issue to components that are disposed of or classified as held for sale, including the HPL disposition. (see "Houston Pipe Line Company" section of Note 7).

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 business combinations, operating segments, liabilities and equity, revenue recognition, pension plans, fair value measurements, accounting changes and related tax impacts. We also expect to see more FASB projects as a result of their 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 2004 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and at state commissions. The Rate Matters note within our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending. The following sections discuss current activities and update the 2004 Annual Report.

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 submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation 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.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, PSO estimates that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power for 2003. Management is unable to predict if the OCC will order a prudence review of PSO's fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Michigan Fuel Recovery Plan

In September 2004, I&M filed its 2005 Power Supply Cost Recovery (PSCR) Plan, with the requested PSCR factors implemented pursuant to the statute effective with January 2005 billings, replacing the 2004 factors. On March 29, 2005, the Michigan Public Service Commission (MPSC) issued an order approving a settlement agreement authorizing the proposed 2005 PSCR Plan factors.

On March 31, 2005, I&M filed its 2004 PSCR Reconciliation seeking recovery of approximately $2 million of unrecovered PSCR fuel costs and interest proposed to be recovered through the application of customer bill surcharges during October 2005 through December 2005.

On April 28, 2005, the MPSC issued an Opinion and Order approving I&M's proposed 2004 PSCR factors as billed and finding in favor of I&M on all issues, including the proposed treatment of net SO_2 and NO_x credits.

Indiana Settlement Agreement

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005, and filed the agreement with the IURC on March 14, 2005. The IURC may rule on the agreement during the second quarter of 2005.

The filed settlement freezes fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel rate freeze period, I&M will receive credit for 30% of the savings produced and customers will be credited with 70% of these savings over the first two fuel filings after the fuel rate freeze period ends in June 2007.

Pending approval of the IURC, this settlement agreement also freezes base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this freeze period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

If the settlement is approved by the IURC, fuel costs previously expensed since January 2005 exceeding the previously authorized level of 9.2 mills up to 9.88 mills (approximately $4 million through March 31, 2005) would be deferred for future recovery. If future fuel cost per KWH exceeds the caps, or if the base rate freeze precludes I&M from seeking timely rate increases to recover increases in I&M's cost of service, future results of operations and cash flows would be adversely affected.

TCC Rate Case

TCC has an on-going transmission and distribution (T&D) rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If TCC were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing TCC's rates could have an adverse effect on future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale of the AEP REPs is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. In June 2003, the Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $3 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on TCC's and TNC's future results of operations and cash flows.

PSO Rate Review

PSO is involved in a commission staff-initiated rate review before the OCC. In that proceeding, PSO made a filing seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

RTO Formation/Integration

Prior to joining PJM, the AEP East companies deferred costs incurred under FERC orders to originally form a new RTO, (the Alliance) and subsequently to join an existing RTO (PJM). In 2004, we requested permission to amortize beginning January 1, 2005 the $18 million of deferred non-PJM billed formation/integration costs over 15 years and the $17 million of deferred PJM-billed integration costs, but we did not propose an amortization period for the PJM-billed costs in the application. The FERC has approved our application.

In January 2005, the AEP East companies began amortizing their deferred non-PJM billed costs over 15 years and the deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was $1 million in the first quarter of 2005. As of March 31, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

On March 8, 2005, we jointly filed with other utilities a request with the FERC to recover deferred PJM-billed integration costs of $17 million from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. On March 31, 2005, we also filed a request for a revised network integration transmission service revenue requirement for the AEP zone of PJM. Included in the costs reflected in that revenue requirement was the budgeted 2005 amortization of our deferred non-PJM billed Alliance RTO formation and PJM integration costs. The AEP East companies will be responsible for paying most of the amounts allocated by the FERC to the AEP East zone since the costs are attributable to their internal load.

Although several parties have filed protests of the joint filing to recover the deferred PJM-billed integration costs, we believe that it is probable that the FERC will ultimately approve recovery of the PJM-billed integration costs through the PJM OATT and that the FERC will grant a long enough amortization period to allow us to recover the deferred non-PJM billed Alliance RTO formation and PJM integration costs in the AEP East retail jurisdictions. If the FERC issues an adverse ruling, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005. SECA billings by PJM crediting AEP for their SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005.

In a March 2005 FERC filing, we proposed an increase in the rate for network integration transmission service, as well as rates for other ancillary services. The primary customers of these services are the municipal and cooperative wholesale entities that have load delivery points in the AEP zone of PJM. As proposed, the rates will automatically increase to reflect the loss of SECA transition rates on April 1, 2006.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding

In a July 2002 order conditionally accepting our choice to join PJM, the FERC directed us, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO.

In July 2004, AEP and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for May 2005.

The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 million to $70 million over the term of the agreement for AEP and ComEd. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120,000. Settlement negotiations are in progress with the remaining Michigan companies.

At this time, management is unable to predict the outcome of this proceeding. AEP will support vigorously its positions before the FERC. If the FERC ultimately approves a significant hold-harmless payment to the Michigan utilities, it would adversely impact results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2004 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 and update the 2004 Annual Report.

OHIO RESTRUCTURING

On January 26, 2005, the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter of 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding their approval of the rate stabilization plans. On March 23, 2005, the PUCO denied all applications for rehearing. In April 2005, an intervenor filed an appeal to the Ohio Supreme Court. Management cannot predict the ultimate impact appeal proceedings will have on future results of operations and cash flows.

TEXAS RESTRUCTURING

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items in TCC's future true-up filing. TCC has asked permission from the PUCT to file its True-up Proceeding after the sales of its interest in STP have been concluded, with only the ownership interest in Oklaunion remaining to be settled. If the request is approved, it is anticipated that TCC's True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of its net regulatory asset of $1.6 billion for its net stranded cost and other true-up items, which it believes the Texas Restructuring Legislation allows.

The Components of TCC's Net True-up Regulatory Asset as of March 31, 2005 and December 31, 2004 are:

	TCC	
	March 31, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1,141	1,136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1,346	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

The Components of TNC's Net True-up Regulatory Liability as of March 31, 2005 and December 31, 2004 are:

	TNC	
	March 31, 2005	**December 31, 2004**
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component which is not recoverable in fuel rates. In the first quarter of 2005, TCC recorded a provision for fuel revenue refund of $3 million, inclusive of interest, for this decision and continued to accrue interest on the deferred over-recovered fuel balance. This provision for refund results in a deferred over-recovery balance of $215 million as of March 31, 2005.

TCC Carrying Costs on Net True-up Regulatory Assets

TCC continues to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on TCC's net stranded cost and other true-up items which was applied retroactively to January 1, 2004. In the first quarter of 2005, TCC accrued carrying costs of $21 million which was more than offset by an adjustment based on this order of $27 million. The net reduction of $6 million in carrying costs is included in Other Income in the first quarter of 2005 on the accompanying Consolidated Statements of Income.

As of March 31, 2005, TCC has computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying costs of $154 million will be recognized in income as collected.

TCC Unrefunded Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first quarter of 2005, TCC refunded an additional $4 million reducing its unrefunded excess earnings to $6 million.

TCC True-up Proceeding

When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated T&D rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

The nonaffiliated utility's March order also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the competition transition charges (CTC). TCC estimates its present value ADFIT benefit to be $212 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's entire net true-up regulatory asset. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset over recovery periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in TCC's future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In January 2005, intervenors made various recommendations including an increase in excess earnings of $5 million and a T&D rate reduction of $3 million annually. The intervenors also recommended that TNC's fuel over-recovery should be increased by $2 million. TNC is awaiting a PUCT decision and order and has recorded no disallowances based on intervenor contentions.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001. In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. TNC will pursue vigorously its appeals, but cannot predict their outcome.

5. <u>COMMITMENTS AND CONTINGENCIES</u>

As discussed in the Commitments and Contingencies note within our 2004 Annual Report, we continue to be involved in various legal matters. The 2004 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 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) carbon dioxide public nuisance claims, (2) nuclear matters, (3) construction commitments, (4) potential uninsured losses, (5) shareholder lawsuits, (6) coal transportation dispute, (7) Bank of Montreal Claim and (8) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2004 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 nonaffiliated 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 occurred 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.

In June 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 filed a motion to amend its complaint and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, the Federal EPA and eight Northeastern states each filed an additional complaint containing the same allegations against the Amos and Conesville plants that the judge disallowed in the pending case. These complaints have been assigned to the same judge in the Southern District Court. AEP filed an answer to the complaint in January 2005, denying the allegations and stating its defenses.

In August 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, a nonaffiliated 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 nonroutine 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 settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at its plant.

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.

In August 2003, the District Court for the Middle District of South Carolina issued a decision in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court 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. The District Court denied the Federal EPA's motion. In April 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated 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. The case is fully briefed and oral argument was heard in February 2005.

In June 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 (TVA) 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.

In June 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. Briefing continues in this case and oral argument was held in January 2005.

In December 2000, Cinergy Corp., a nonaffiliated 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.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. CSPCo owns a 26% share of the J.M. Stuart Station. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against TVA, the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. 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.

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

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 CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, 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. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May 2005.

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 value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

Operational

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000, (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We 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's 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 (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA.

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 these electric power products 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 the 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 SUEZ-TRACTEBEL S.A. under the guaranty, damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

Enron Bankruptcy

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

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate 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 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. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. On April 6, 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In January 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of the 98% interest in HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding, 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 nonbinding, 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. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but were subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine. We will continue to defend vigorously each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied in September 2004. Plaintiffs have filed a Motion for Class Certification. The defendants, including AEP and AEPES, filed their opposition to class certification on April 8, 2005. Briefing on the issue of class certification is expected to be completed in the second quarter of 2005. Discovery is continuing in the case with a discovery cut-off date of June 30, 2005. We intend to defend vigorously against these claims.

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 of our subsidiaries, certain nonaffiliated 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, 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. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002 in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (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. We issued all of these LOCs in our ordinary course of business. At March 31, 2005, the maximum future payments for all the LOCs were approximately $234 million with maturities ranging from May 2005 to April 2007. As the parent of the various subsidiaries that have issued these LOCs, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these LOCs are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $51 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At March 31, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and the first three months of 2005, we entered into several sale agreements. An update of the status of sales agreements is discussed in Note 7. These sale agreements include indemnifications with a maximum exposure of approximately $1.9 billion. There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At March 31, 2005, the maximum potential loss for this lease agreement was approximately $43 million ($28 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. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At March 31, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year terms to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of structure.

7. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS COMPLETED AND ANTICIPATED BEING COMPLETED DURING THE FIRST HALF OF 2005

Houston Pipe Line Company (Investments – Gas Operations segment)

In January 2005, we sold a 98% controlling interest in HPL, 30 BCF of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL and provide certain transitional administrative services to the buyer. Although the assets have been legally transferred, it is not possible to determine all costs associated with the transfer until the BOA litigation is resolved. Accordingly, we have deferred the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $407 million as of March 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Consolidated Balance Sheets. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see “Enron Bankruptcy – Right to Use of Cushion Gas Agreements” section of Note 5). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008, the cushion gas arrangement and our 2% ownership interest.

We also have a put option expiring in 2006, which allows us to sell our remaining 2% interest to the buyer for approximately $16 million.

Pacific Hydro Limited (Investments – Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $83 million. The sale is contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. If the sale occurs, we will recognize an estimated pretax gain of approximately $50 million.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement.

There has been an ongoing dispute between AEP and Centrica related to the ESM calculation. In March 2005, AEP and Centrica entered into a series of agreements resulting in the resolution of open issues related to the sale and the disputed ESM payments for 2003 and 2004. Also in March 2005, we received payments of $45 million and $70 million related to the ESM payments for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in the first quarter of 2005, which is reflected in Other Income on our accompanying Consolidated Statements of Income. The ESM payments for 2005 and 2006 are contingent on Centrica's future operating results and are capped at $70 million and $20 million, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap.

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. We do not expect the sale to have a significant effect on our future results of operations. We expect the sale to close in the second quarter of 2005. TCC's assets and liabilities related to STP have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

DISCONTINUED OPERATIONS

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-month periods ended March 31, 2005 and 2004 as shown in the following table:

	SEEBOARD (a)	U.K. Operations (b)	Total
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income (Loss)	-	(8)	(8)
2005 Income (Loss) After tax	6	(5)	1

	Pushan Power Plant	LIG (c)	U.K. Operations	Total
2004 Revenue	$ 10	$ 160	$ 41	$ 211
2004 Pretax Income (Loss)	-	(1)	(19)	(20)
2004 Income (Loss) After tax	6	(1)	(12)	(7)

(a) Includes a tax adjustment related to the sale of SEEBOARD.
(b) Relates primarily to purchase price true-up adjustments.
(c) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.

During the quarter ended March 31, 2004, the net increase in cash and cash equivalents of discontinued operations was $24 million, primarily from the cash flows from operating activities of the discontinued operations.

ASSETS HELD FOR SALE

The assets and liabilities of the entities that were classified as held for sale at March 31, 2005 and December 31, 2004 are as follows:

	Texas Plants	
	March 31, 2005	December 31, 2004
Assets:	(in millions)	
Other Current Assets	$ 25	$ 24
Property, Plant and Equipment, Net	416	413
Regulatory Assets	52	48
Nuclear Decommissioning Trust Fund	143	143
Total Assets Held for Sale	$ 636	$ 628
Liabilities:		
Regulatory Liabilities	$ 1	$ 1
Asset Retirement Obligations	254	249
Total Liabilities Held for Sale	$ 255	$ 250

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost for the following plans for the three months ended March 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Service Cost	$ 23	$ 22	$ 11	$ 10
Interest Cost	56	56	27	29
Expected Return on Plan Assets	(77)	(72)	(23)	(20)
Amortization of Transition (Asset) Obligation	-	-	7	7
Amortization of Net Actuarial Loss	13	4	7	9
Net Periodic Benefit Cost	$ 15	$ 10	$ 29	$ 35

9. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations

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

Investments - Gas Operations (a)

- Gas pipeline and storage services.
- Gas marketing and risk management activities.

Investments - UK Operations (b)

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.

Investments – Other (c)

- Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

(a) Operations of Louisiana Intrastate Gas, including Jefferson Island Storage, were classified as Discontinued Operations during 2003 and were sold during the third and fourth quarter of 2004, respectively. A ninety-eight percent interest in HPL was sold during the first quarter of 2005.
(b) UK Operations were classified as Discontinued Operations during 2003 and were sold during the third quarter of 2004.
(c) Four independent power producers were sold during the third and fourth quarters of 2004.

With the sale of HPL during January 2005, we have substantially completed planned disposals of all significant non-core assets. Accordingly, effective with the quarter ended March 31, 2005, certain subsidiaries representing shared service functions and costs were reclassified to Utility Operations and Investments - Other from either Investments – Other or All Other. Such reclassifications were deemed necessary given the remaining compositions of the individual segments and the nature of the shared service functions and costs. The 2004 information presented herein has been reclassified to conform to the 2005 presentation.

The tables below present segment income statement information for the three months ended March 31, 2005 and 2004 and balance sheet information as of March 31, 2005 and December 31, 2004. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

Three Months Ended March 31, 2005	**Utility Operations**	**Investments – Gas Operations**	**Investments – UK Operations**	**Investments – Other**	**All Other (a)**	**Reconciling Adjustments (b)**	**Consolidated**
				(in millions)			
Revenues from:							
External Customers	$ 2,537	$ 357	$ -	$ 89	$ -	$ -	$ 2,983
Other Operating Segments	77	(73)	-	3	1	(8)	-
Total Revenues	$ 2,614	$ 284	$ -	$ 92	$ 1	$ (8)	$ 2,983
Income (Loss) Before Discontinued Operations	$ 353	$ 10	$ -	$ 5	$ (14)	$ -	$ 354
Discontinued Operations, Net of Tax	-	-	(5)	6	-	-	1
Net Income (Loss)	$ 353	$ 10	$ (5)	$ 11	$ (14)	$ -	$ 355
As of March 31, 2005							
Total Property, Plant and Equipment	$ 36,348	$ 2	$ -	$ 835	$ 3	$ -	$ 37,188
Accumulated Depreciation and Amortization	14,494	1	-	93	1	-	14,589
Total Property, Plant and Equipment - Net	$ 21,854	$ 1	$ -	$ 742	$ 2	$ -	$ 22,599
Total Assets	$ 32,655	$ 1,295	$ 597(c)	$ 1,557	$ 10,740	$ (11,747)	$ 35,097
Assets Held for Sale	636	-	-	-	-	-	636

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $597 million for the Investments-UK Operations segment include $551 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $46 million in assets represents cash equivalents along with value-added tax receivables.

Three Months Ended March 31, 2004	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 2,581	$ 652	$ -	$ 131	$ -	$ -	$ 3,364
Other Operating Segments	21	24	-	16	6	(67)	-
Total Revenues	$ 2,602	$ 676	$ -	$ 147	$ 6	$ (67)	$ 3,364
Income (Loss) Before Discontinued Operations	$ 304	$ (10)	$ -	$ 4	$ (9)	$ -	$ 289
Discontinued Operations, Net of Tax	-	(1)	(12)	6	-	-	(7)
Net Income (Loss)	$ 304	$ (11)	$ (12)	$ 10	$ (9)	$ -	$ 282
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,006	$ 445	$ -	$ 832	$ 3	$ -	$ 37,286
Accumulated Depreciation and Amortization	14,355	43	-	86	1	-	14,485
Total Property, Plant and Equipment - Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,175	$ 1,789	$ 221(c)	$ 2,071	$ 8,093	$ (9,686)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

10. FINANCING ACTIVITIES

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2005 are shown in the table below.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 200	4.95%	2015
OPCo	Installment Purchase Contracts	164	Variable	2028
OPCo	Installment Purchase Contracts	54	Variable	2029
TCC	Installment Purchase Contracts	162	Variable	2030
Non-Registrant:				
AEP Subsidiary	Notes Payable	6	Variable	2009
Total Issuances		$ 586(a)		

(a) Amount indicated on statement of cash flows of $580 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
Retirements and Principal Payments:				
AEP	Other Debt	$ 3	Variable	2007
AEP and Subsidiaries	Other	6(b)	Variable	Various
OPCo	Installment Purchase Contracts	102	6.375%	2029
OPCo	Installment Purchase Contracts	80	Variable	2028
OPCo	Installment Purchase Contracts	36	Variable	2029
OPCo	Notes Payable	1	6.81%	2008
OPCo	Notes Payable	3	6.27%	2009
SWEPCo	Notes Payable	2	4.47%	2011
SWEPCo	Notes Payable	1	Variable	2008
TCC	Senior Unsecured Notes	150	3.00%	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	Securitization Bonds	29	3.54%	2005
Non-Registrant:				
AEP Subsidiary	Notes Payable	3	Variable	2017
Total Retirements		$ 516(c)		

(b) Amount reflects mark-to-market of risk management contracts.
(c) Amount indicated on statement of cash flows of $510 million does not include $6 million related to the mark-to-market of risk management contracts.

Preferred Stock Redemption

In January 2005, the following outstanding shares of preferred stock were redeemed:

Company	Series	Number of Shares Redeemed	Amount (in millions)
I&M	5.900%	132,000	$ 13
I&M	6.250%	192,500	19
I&M	6.875%	157,500	16
I&M	6.300%	132,450	13
OPCo	5.900%	50,000	5
			$ 66

Common Stock Repurchase

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The 12.5 million shares repurchased under the program are held in treasury and are subject to a future contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period. Based on this adjustment, an asset of $2 million is reflected in Accounts Receivable on our Consolidated Balance Sheets as of March 31, 2005 due to the fact that the actual stock purchase prices were less than our initial payment.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Operating revenues are derived from the sale of our share 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. Fluctuations in Net Income are a result of terms in the unit power agreements which allow for the calculation of return on total capital monthly.

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 1.8
Change in Gross Margin:		
Wholesale Sales		(2.5)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	3.8	
Depreciation and Amortization	(0.2)	
Taxes Other Than Income Taxes	(0.1)	
Interest Charges	(0.1)	
Total Change in Operating Expenses and Other		3.4
Income Tax Expense		(0.2)
First Quarter of 2005 Net Income		$ 2.5

Gross Margin decreased $2.5 million primarily due to a decrease in operation and maintenance expense. Gross Margin fluctuates consistent with operation and maintenance expense in accordance with the unit power agreements.

The decrease in Other Operation and Maintenance expenses resulted from decreased outages and the related costs compared to prior year. In 2004, Rockport Plant Unit 2 was shutdown for planned boiler inspection and repairs from early February through the end of the quarter.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 1.8% and (9.5)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences and state income taxes. The increase in the effective tax rate is primarily due to higher pretax income in 2005.

Off-Balance Sheet Arrangement

In prior years, we entered into an off-balance sheet arrangement. Our current policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly since year-end. For complete information on our off-balance sheet arrangement see "Off-balance Sheet Arrangements" in the "Management's Narrative Discussion and Analysis" section of our 2004 Annual Report.

<u>Significant Factors</u>

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

<u>Critical Accounting Estimates</u>

See “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES	$ 66,546	$ 55,282
OPERATING EXPENSES		
Fuel for Electric Generation	35,135	21,398
Rent – Rockport Plant Unit 2	17,071	17,071
Other Operation	2,385	2,490
Maintenance	1,718	5,400
Depreciation and Amortization	5,956	5,734
Taxes Other Than Income Taxes	1,024	944
Income Taxes	936	698
TOTAL	64,225	53,735
OPERATING INCOME	2,321	1,547
Nonoperating Income	-	24
Nonoperating Expenses	64	69
Nonoperating Income Tax Credit	891	857
Interest Charges	632	532
NET INCOME	$ 2,516	$ 1,827

STATEMENTS OF RETAINED EARNINGS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
BALANCE AT BEGINNING OF PERIOD	$ 24,237	$ 21,441
Net Income	2,516	1,827
Cash Dividends Declared	940	1,262
BALANCE AT END OF PERIOD	$ 25,813	$ 22,006

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
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 682,162	$ 681,254
General	3,923	3,739
Construction Work in Progress	6,990	7,729
Total	693,075	692,722
Accumulated Depreciation and Amortization	373,165	368,484
TOTAL - NET	319,910	324,238
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	24,248	23,078
Fuel	10,613	16,404
Materials and Supplies	6,337	5,962
Prepayments	35	-
TOTAL	41,233	45,444
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,437	4,496
Asset Retirement Obligations	1,165	1,117
Deferred Property Taxes	3,441	557
Other Deferred Charges	417	422
TOTAL	9,460	6,592
TOTAL ASSETS	$ 370,722	$ 376,393

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

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock – $1,000 par value per share:		
Authorized and Outstanding – 1,000 shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	25,813	24,237
Total Common Shareholder's Equity	50,247	48,671
Long-term Debt	44,822	44,820
TOTAL	95,069	93,491
CURRENT LIABILITIES		
Advances from Affiliates	7,131	26,915
Accounts Payable:		
General	990	443
Affiliated Companies	14,405	17,905
Taxes Accrued	9,165	8,806
Interest Accrued	456	911
Obligations Under Capital Leases	285	210
Rent Accrued – Rockport Plant Unit 2	23,427	4,963
Other	102	73
TOTAL	55,961	60,226
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	23,687	24,762
Regulatory Liabilities:		
Asset Removal Costs	25,965	25,428
Deferred Investment Tax Credits	45,416	46,250
SFAS 109 Regulatory Liability, Net	12,735	12,852
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	98,512	99,904
Obligations Under Capital Leases	12,137	12,264
Asset Retirement Obligations	1,240	1,216
TOTAL	219,692	222,676
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 370,722	$ 376,393

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

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 2,516	$ 1,827
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	5,956	5,734
Deferred Income Taxes	(1,192)	(656)
Deferred Investment Tax Credits	(834)	(834)
Deferred Property Taxes	(2,884)	(2,439)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(1,392)	(1,392)
Change in Other Noncurrent Assets	(233)	91
Change in Other Noncurrent Liabilities	436	(156)
Changes in Components of Working Capital:		
Accounts Receivable	(1,170)	7,145
Fuel, Materials and Supplies	5,416	(3,687)
Accounts Payable	(2,953)	(243)
Taxes Accrued	359	4,539
Interest Accrued	(455)	(455)
Rent Accrued – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(35)	(32)
Other Current Liabilities	104	28
Net Cash Flows From Operating Activities	22,103	27,934
INVESTING ACTIVITIES		
Construction Expenditures	(1,379)	(7,525)
Net Cash Flows Used For Investing Activities	(1,379)	(7,525)
FINANCING ACTIVITIES		
Changes in Advances from Affiliates, Net	(19,784)	(19,147)
Dividends Paid	(940)	(1,262)
Net Cash Flows Used For Financing Activities	(20,724)	(20,409)
Net Increase in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $1,021,000 and $921,000 and for income taxes was $5,439,000 and $(218,000) in 2005 and 2004, 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.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 29
Changes in Gross Margin:		
Texas Wires	2	
Texas Supply	(35)	
Off-system Sales	(2)	
Other Revenues	(9)	
Total Change in Gross Margin		(44)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	8	
Nonoperating Income and Expense, Net	(11)	
Interest Charges	6	
Total Change in Operating Expenses and Other		3
Income Tax Expense		13
First Quarter of 2005 Net Income		$ 1

Net Income decreased $28 million to $1 million in the first quarter of 2005. The key drivers of the decrease were a $44 million decrease in gross margin partially offset by a net decrease in Other Operation and Maintenance of $8 million and by a $13 million decrease in Income Tax Expense.

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

- Texas Supply margins were $35 million less than the prior period primarily due to the loss of our largest REP customer of $77 million and loss of ERCOT reliability-must-run margins of $6 million and capacity sales of $9 million due to the sale of certain generation plants in the third quarter of 2004, offset by lower fuel expense of $57 million.
- Other Revenues for 2005 decreased $9 million in comparison to 2004 primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $8 million primarily due to a decrease in production plant operations and maintenance expenses as a result of the sale of certain generation plants in the third quarter of 2004.
- Nonoperating Income and Expense, Net decreased partially due to carrying costs on stranded cost recovery of $21 million recorded in the first quarter of 2005, offset by an adjustment of $27 million. The adjustment relates to a nonaffiliated utility's securitization proceeding where the PUCT issued an order in March 2005 that resulted in a reduction in the nonaffiliated utility's carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes retroactive to January 1, 2004.

- In addition, Nonoperating Income and Expense, Net decreased $6 million partially due to the absence of risk management activities in the first quarter of 2005.
- Interest Charges decreased $6 million primarily due to the defeasance of $112 million of First Mortgage Bonds in 2004 and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, long-term debt maturities and other financing activities.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were (906.2)% and 29.0%, 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, consolidated tax savings from parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to lower pretax income in 2005, federal income tax adjustments and consolidated tax savings from parent, offset in part by a decrease in 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 three months ended March 31, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ -	$ 760
Cash flows from (used for):		
Operating activities	(121,316)	25,873
Investing activities	3,997	4,582
Financing activities	118,292	(29,182)
Net increase in cash and cash equivalents	973	1,273
Cash and cash equivalents at end of period	$ 973	$ 2,033

Operating Activities

Our net cash flows used for operating activities were $121 million for the first three months of 2005. We produced income of $1 million during the period including noncash expense items of $29 million for Depreciation and Amortization and $(30) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relate to a number of items; the most significant are decreases in Accounts Payable, Taxes Accrued and Interest Accrued offset in part by an increase in Accounts Receivable, Net. Accounts Payable decreased $41 million primarily due to lower vendor related payables and lower third party energy transactions. Taxes Accrued decreased $118 million primarily due to a Federal income tax payment offset by the annual tax accruals related to 2005 property taxes. Interest Accrued decreased $22 million primarily due to interest payments on debentures and senior unsecured notes offset by monthly accruals.

Our net cash flows from operating activities were $26 million for the first three months of 2004. We produced income of $29 million during the period including noncash expense items of $29 million for Depreciation and Amortization and $(34) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in these asset and liability accounts relates to a number of items; the most significant is an increase in Taxes Accrued offset by decreases in Accounts Payable and Interest Accrued. Taxes Accrued increased $32 million primarily due to the annual tax accruals related to property taxes net of a payment in 2004 and by a decrease in Federal income tax refunds. Accounts Payable decreased $14 million primarily due to decreased trading related payables and fewer fuel related shipments. Interest Accrued decreased $20 million primarily due to interest payments on debentures and senior unsecured notes offset by monthly accruals.

Investing Activities

Cash Flows From Investing Activities were $4 million in 2005 primarily due to a decrease of $32 million in Other Cash Deposits, Net related to principal payments on transition funding bonds offset by Construction Expenditures of $28 million related to projects for improved transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $180 million.

Cash Flows From Investing Activities were $5 million in 2004 primarily due to a decrease of $28 million in Other Cash Deposits, Net related to principal payments on transition funding bonds offset by Construction Expenditures of $24 million related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash Flows From Financing Activities of $118 million in 2005 were due to a $238 million increase in Advances to/from Affiliates, Net and issuances of Installment Purchase Contracts of $159 million offset by retirements of Senior Unsecured Note Payables and Securitization Bonds of $279 million.

Cash Flows Used for Financing Activities of $29 million in 2004 were due to retirements of long-term debt, payment of dividends and increased Advances to Affiliates.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2005 were:

<u>Issuances</u>

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	**(%)**	
Installment Purchase Contract	$111,700	Variable	2030
Installment Purchase Contract	50,000	Variable	2030

<u>Retirements</u>

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	**(%)**	
Senior Unsecured Note Payable	$150,000	3.00	2005
Senior Unsecured Note Payable	100,000	Variable	2005
Securitization Bonds	29,386	3.54	2005

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity. Finally, we expect to receive asset sale proceeds of approximately $333 million in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals.

Significant Factors

Texas Restructuring

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of our net stranded generation costs and other recoverable true-up items in our future true-up filing. We have asked permission from the PUCT to file our True-up Proceeding after the sales of our interest in STP have been concluded. If the request is approved, it is anticipated that our True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of our net regulatory asset of $1.6 billion for our net stranded cost and other true-up items which we believe the Texas Restructuring Legislation allows.

We continue to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until we recover our approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 further clarifying how the amounts are to be calculated. This resulted in a reduction in our accrued carrying costs based on the methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on our net stranded cost and other true-up items retroactive to January 1, 2004. In the first quarter of 2005, we accrued carrying costs of $21 million, which was more than offset by an adverse adjustment of $27 million based on this order. The net reduction of $6 million in carrying costs is included in Nonoperating Income in the first quarter of 2005 on our accompanying Consolidated Statements of Income.

As of March 31, 2005, we have computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying cost of $154 million will be recognized in income as collected.

When the True-up Proceeding is completed, we intend to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated transmission and distribution rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in our future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on our future results of operations, cash flows and possibly financial condition.

TCC Rate Case

We have an on-going transmission and distribution rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If we were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing our rates could have an adverse effect on future results of operations and cash flows.

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

Critical Accounting Estimates

See “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	9,701
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,113)
Fair Value of New Contracts When Entered During the Period (b)		33
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(3,799)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		2,822
Net Cash Flow Hedge Contracts (f)		(4,221)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2005	$	(1,399)

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(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 in 2005.

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

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 4,951	$ 2,116	$ 7,067
Noncurrent Assets	4,275	46	4,321
Total MTM Derivative Contract Assets	9,226	2,162	11,388
Current Liabilities	(4,394)	(6,269)	(10,663)
Noncurrent Liabilities	(2,010)	(114)	(2,124)
Total MTM Derivative Contract Liabilities	(6,404)	(6,383)	(12,787)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,822	$ (4,221)	$ (1,399)

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (609)	$ 234	$ 485	$ -	$ -	$ -	$ 110
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,185	1,006	740	317	-	-	3,248
Prices Based on Models and Other Valuation Methods (b)	14	(855)	(713)	173	381	464	(536)
Total	$ 590	$ 385	$ 512	$ 490	$ 381	$ 464	$ 2,822

(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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

		Power
Beginning Balance December 31, 2004	$	657
Changes in Fair Value (a)		(4,094)
Reclassifications from AOCI to Net Income (b)		(242)
Ending Balance March 31, 2005	$	(3,679)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $3,634 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$40	$88	$43	$26	$157	$511	$220	$75

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 $127 million and $120 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 182,194	$ 268,858
Sales to AEP Affiliates	4,964	18,130
TOTAL	187,158	286,988
OPERATING EXPENSES		
Fuel for Electric Generation	6,075	23,106
Fuel from Affiliates for Electric Generation	23	40,199
Purchased Electricity for Resale	15,370	10,086
Purchased Electricity from AEP Affiliates	-	4,073
Other Operation	65,660	75,441
Maintenance	17,039	15,404
Depreciation and Amortization	29,286	29,097
Taxes Other Than Income Taxes	22,531	22,057
Income Taxes	1,461	12,006
TOTAL	157,445	231,469
OPERATING INCOME	29,713	55,519
Nonoperating Income	11,155	12,102
Nonoperating Expenses	15,137	5,108
Nonoperating Income Tax Credit	2,485	20
Interest Charges	27,079	33,129
NET INCOME	1,137	29,404
Preferred Stock Dividend Requirements	60	60
EARNINGS APPLICABLE TO COMMON STOCK	$ 1,077	$ 29,344

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 55,292	$ 132,606	$ 1,083,023	$ (61,872)	$ 1,209,049
Common Stock Dividends			(24,000)		(24,000)
Preferred Stock Dividends			(60)		(60)
TOTAL					1,184,989
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,411				(13,763)	(13,763)
Minimum Pension Liability, Net of Tax of $0				(2,466)	(2,466)
NET INCOME			29,404		29,404
TOTAL COMPREHENSIVE INCOME					13,175
MARCH 31, 2004	$ 55,292	$ 132,606	$ 1,088,367	$ (78,101)	$ 1,198,164
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643
Preferred Stock Dividends			(60)		(60)
TOTAL					1,268,583
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,335				(4,336)	(4,336)
NET INCOME			1,137		1,137
TOTAL COMPREHENSIVE LOSS					(3,199)
MARCH 31, 2005	$ 55,292	$ 132,606	$ 1,085,981	$ (8,495)	$ 1,265,384

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Transmission	$ 791,529	$ 788,371
Distribution	1,443,548	1,433,380
General	219,463	220,435
Construction Work in Progress	53,481	50,612
Total	2,508,021	2,492,798
Accumulated Depreciation and Amortization	729,655	725,225
TOTAL - NET	1,778,366	1,767,573
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	2,360	1,577
Bond Defeasance Funds	21,642	22,110
TOTAL	24,002	23,687
CURRENT ASSETS		
Cash and Cash Equivalents	973	-
Other Cash Deposits	103,601	135,132
Accounts Receivable:		
Customers	156,320	157,431
Affiliated Companies	12,168	67,860
Accrued Unbilled Revenues	23,327	21,589
Allowance for Uncollectible Accounts	(688)	(3,493)
Materials and Supplies	12,240	12,288
Risk Management Assets	7,067	14,048
Margin Deposits	2,778	1,891
Prepayments and Other Current Assets	15,464	9,151
TOTAL	333,250	415,897
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	18,562	15,236
Wholesale Capacity Auction True-Up	574,027	559,973
Unamortized Loss on Reacquired Debt	11,576	11,842
Designated for Securitization	1,345,935	1,361,299
Deferred Debt – Restructuring	11,368	11,596
Other	95,921	102,032
Securitized Transition Assets	632,000	642,384
Long-term Risk Management Assets	4,321	9,508
Prepaid Pension Obligations	109,995	109,628
Deferred Property Taxes	29,820	-
Deferred Charges	33,951	36,986
TOTAL	2,867,476	2,860,484
Assets Held for Sale – Texas Generation Plants	635,776	628,149
TOTAL ASSETS	$ 5,638,870	$ 5,695,790

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
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized – 12,000,000 shares		
Outstanding – 2,211,678 shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,085,981	1,084,904
Accumulated Other Comprehensive Income (Loss)	(8,495)	(4,159)
Total Common Shareholder's Equity	1,265,384	1,268,643
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,271,324	1,274,583
Long-term Debt - Nonaffiliated	1,672,695	1,541,552
TOTAL	2,944,019	2,816,135
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	116,997	365,742
Advances from Affiliates	238,693	207
Accounts Payable:		
General	64,384	109,688
Affiliated Companies	68,003	64,045
Customer Deposits	4,974	6,147
Taxes Accrued	66,229	184,014
Interest Accrued	19,589	41,227
Risk Management Liabilities	10,663	8,394
Obligations Under Capital Leases	431	412
Other	17,511	20,115
TOTAL	607,474	799,991
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,253,495	1,247,111
Long-term Risk Management Liabilities	2,124	4,896
Regulatory Liabilities:		
Asset Removal Costs	103,419	102,624
Deferred Investment Tax Credits	106,677	107,743
Over-recovery of Fuel Costs	214,426	211,526
Retail Clawback	61,384	61,384
Other	74,318	76,653
Obligations Under Capital Leases	498	468
Deferred Credits and Other	16,525	17,276
TOTAL	1,832,866	1,829,681
Liabilities Held for Sale – Texas Generation Plants	254,511	249,983
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,638,870	$ 5,695,790

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 Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 1,137	$ 29,404
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	29,286	29,097
Accretion Expense	4,529	4,067
Deferred Income Taxes	(5,045)	(3,401)
Deferred Investment Tax Credits	(1,066)	(1,302)
Deferred Property Taxes	(29,820)	(33,660)
Pension and Postemployment Benefit Reserves	(1,072)	259
Mark-to-Market of Risk Management Contracts	6,879	5,035
Pension Contributions	(57)	-
Carrying Costs	5,141	-
Wholesale Capacity Auction True-up	769	-
Over/Under Fuel Recovery	2,900	13,000
(Gain)/Loss on Sale of Assets	(48)	(49)
Change in Other Noncurrent Assets	(7,731)	1,439
Change in Other Noncurrent Liabilities	6,929	(11,037)
Changes in Components of Working Capital:		
Accounts Receivable, Net	52,260	937
Fuel, Materials and Supplies	98	499
Accounts Payable	(41,346)	(14,259)
Taxes Accrued	(117,785)	31,652
Customer Deposits	(1,173)	1,974
Interest Accrued	(21,638)	(19,948)
Other Current Assets	(1,879)	(2,527)
Other Current Liabilities	(2,584)	(5,307)
Net Cash Flows From (Used For) Operating Activities	(121,316)	25,873
INVESTING ACTIVITIES		
Construction Expenditures	(27,534)	(23,748)
Change in Other Cash Deposits, Net	31,531	28,330
Net Cash Flows From Investing Activities	3,997	4,582
FINANCING ACTIVITIES		
Issuance of Long-term Debt	159,252	-
Retirement of Long-term Debt	(279,386)	(29,864)
Changes in Advances to/from Affiliates, Net	238,486	24,742
Dividends Paid on Common Stock	-	(24,000)
Dividends Paid on Cumulative Preferred Stock	(60)	(60)
Net Cash Flows From (Used For) Financing Activities	118,292	(29,182)
Net Increase in Cash and Cash Equivalents	973	1,273
Cash and Cash Equivalents at Beginning of Period	-	760
Cash and Cash Equivalents at End of Period	$ 973	$ 2,033

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $44,721,000 and $49,928,000 and for income taxes was $132,960,000 and $(7,567,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $157,000 and $69,000 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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

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

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 13
Changes in Gross Margin:		
Texas Supply	(3)	
Off-system Sales	(2)	
Other Revenues	(4)	
Total Change in Gross Margin		(9)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	2	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	(2)	
Interest Charges	1	
Total Change in Operating Expenses and Other		-
Income Tax Expense		3
First Quarter of 2005 Net Income		$ 7

Net Income decreased $6 million to $7 million in the first quarter of 2005. The key drivers of the decrease were a $9 million decrease in gross margin offset by a $3 million decrease in Income Tax Expense.

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

- Texas Supply margins decreased by $3 million primarily due to the loss of ERCOT reliability-must-run (RMR) revenue of $2 million.
- Margins from Off-system Sales for 2005 decreased by $2 million in comparison to 2004 primarily due to lower optimization activity.
- Other Revenues margins decreased $4 million primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $2 million primarily due to decreased production plant operations and related maintenance for RMR plants no longer in use offset in part by increased transmission cost related to ERCOT.
- Taxes Other Than Income Taxes increased $1 million primarily due to property related taxes offset in part by lower state and local franchise tax expense.
- Nonoperating Income and Expenses, Net decreased $2 million primarily due to the absence of risk management activities in the first quarter of 2005.
- Interest Charges decreased $1 million primarily due to long-term debt maturities in 2004 and interest in 2004 related to the FERC settlement with wholesale customers.

Income Taxes

The effective tax rate for the first quarter of 2005 and 2004 was 33.8% and 34.3%, 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 effective tax rate remained relatively flat for the comparative period.

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

There were no long-term debt issuances or retirements during the first three months of 2005.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	4,192
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(1,345)
Fair Value of New Contracts When Entered During the Period (b)		14
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(1,642)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		1,219
Net Cash Flow Hedge Contracts (f)		1,006
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	2,225

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(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 in 2005.

(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) "Changes 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" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 2,140	$ 2,390	$ 4,530
Noncurrent Assets	1,848	20	1,868
Total MTM Derivative Contract Assets	3,988	2,410	6,398
Current Liabilities	(1,900)	(1,355)	(3,255)
Noncurrent Liabilities	(869)	(49)	(918)
Total MTM Derivative Contract Liabilities	(2,769)	(1,404)	(4,173)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,219	$ 1,006	$ 2,225

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (263)	$ 101	$ 210	$ -	$ -	$ -	$ 48
Prices Provided by Other External Sources - OTC Broker Quotes (a)	512	435	320	137	-	-	1,404
Prices Based on Models and Other Valuation Methods (b)	4	(370)	(308)	75	165	201	(233)
Total	$ 253	$ 166	$ 222	$ 212	$ 165	$ 201	$ 1,219

(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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 285
Changes in Fair Value (a)	(670)
Reclassifications from AOCI to Net Income (b)	(104)
Ending Balance March 31, 2005	$ (489)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $470 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$17	$38	$19	$11	$68	$221	$95	$33

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 $15 million and $13 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 71,943	$ 88,712
Sales to AEP Affiliates	11,290	14,718
TOTAL	83,233	103,430
OPERATING EXPENSES		
Fuel for Electric Generation	12,611	7,500
Fuel from Affiliates for Electric Generation	372	11,224
Purchased Electricity for Resale	16,338	18,023
Purchased Electricity from AEP Affiliates	22	3,532
Other Operation	18,561	20,381
Maintenance	4,219	4,683
Depreciation and Amortization	10,155	9,692
Taxes Other Than Income Taxes	5,705	5,104
Income Taxes	3,586	5,941
TOTAL	71,569	86,080
OPERATING INCOME	11,664	17,350
Nonoperating Income	36,002	13,756
Nonoperating Expenses	35,108	10,936
Nonoperating Income Tax Expense	180	894
Interest Charges	4,984	6,180
NET INCOME	7,394	13,096
Preferred Stock Dividend Requirements	26	26
EARNINGS APPLICABLE TO COMMON STOCK	$ 7,368	$ 13,070

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 137,214	$ 2,351	$ 125,428	$ (26,718)	$ 238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(26)		(26)
TOTAL					236,249
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,482				(4,610)	(4,610)
NET INCOME			13,096		13,096
TOTAL COMPREHENSIVE INCOME					8,486
MARCH 31, 2004	$ 137,214	$ 2,351	$ 136,498	$ (31,328)	$ 244,735
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421
Common Stock Dividends			(9,427)		(9,427)
Preferred Stock Dividends			(26)		(26)
TOTAL					300,968
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $416				(774)	(774)
NET INCOME			7,394		7,394
TOTAL COMPREHENSIVE INCOME					6,620
MARCH 31, 2005	$ 137,214	$ 2,351	$ 168,925	$ (902)	$ 307,588

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

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 288,107	$ 287,212
Transmission	280,447	281,359
Distribution	479,251	474,961
General	115,774	115,174
Construction Work in Progress	21,487	23,621
Total	1,185,066	1,182,327
Accumulated Depreciation and Amortization	407,278	405,933
TOTAL - NET	777,788	776,394
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,167	1,407
CURRENT ASSETS		
Cash and Cash Equivalents	304	-
Other Cash Deposits	2,308	2,308
Advances to Affiliates	52,736	51,504
Accounts Receivable:		
Customers	53,018	90,109
Affiliated Companies	25,696	21,474
Accrued Unbilled Revenues	2,567	3,789
Allowance for Uncollectible Accounts	(30)	(787)
Unbilled Construction Costs	16,127	22,065
Fuel Inventory	5,736	3,148
Materials and Supplies	8,389	8,273
Risk Management Assets	4,530	6,071
Margin Deposits	2,676	818
Prepayments and Other	1,256	1,053
TOTAL	175,313	209,825
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Debt – Restructuring	5,971	6,093
Unamortized Loss on Reacquired Debt	1,805	2,147
Other	3,675	3,783
Long-term Risk Management Assets	1,868	4,110
Prepaid Pension Obligations	44,917	44,911
Deferred Property Taxes	12,218	-
Other Deferred Charges	2,629	2,859
TOTAL	73,083	63,903
TOTAL ASSETS	$ 1,027,351	$ 1,051,529

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

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized – 7,800,000 shares		
Outstanding – 5,488,560 shares	$ 137,214	$ 137,214
Paid-in Capital	2,351	2,351
Retained Earnings	168,925	170,984
Accumulated Other Comprehensive Income (Loss)	(902)	(128)
Total Common Shareholder's Equity	307,588	310,421
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders' Equity	309,945	312,778
Long-term Debt – Nonaffiliated	276,773	276,748
TOTAL	586,718	589,526
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	37,609	37,609
Accounts Payable:		
General	14,955	22,444
Affiliated Companies	53,078	52,801
Customer Deposits	594	1,020
Taxes Accrued	26,357	37,269
Interest Accrued	3,372	5,044
Risk Management Liabilities	3,255	3,628
Obligations Under Capital Leases	227	220
Other	7,344	9,628
TOTAL	146,791	169,663
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	139,898	138,465
Long-term Risk Management Liabilities	918	2,116
Regulatory Liabilities:		
Asset Removal Costs	81,991	81,143
Deferred Investment Tax Credits	18,380	18,698
Over-recovery of Fuel Costs	5,320	3,920
Retail Clawback	13,924	13,924
Excess Earnings	13,146	13,270
SFAS 109 Regulatory Liability, Net	7,824	8,500
Other	1,156	1,319
Obligations Under Capital Leases	383	314
Deferred Credits and Other	10,902	10,671
TOTAL	293,842	292,340
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,027,351	$ 1,051,529

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

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 7,394	$ 13,096
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	10,155	9,692
Deferred Income Taxes	(1,221)	(1)
Deferred Investment Tax Credits	(318)	(339)
Deferred Property Taxes	(12,218)	(11,100)
Mark-to-Market of Risk Management Contracts	2,973	2,096
Over/Under Fuel Recovery	1,400	1,500
Change in Other Noncurrent Assets	(1,705)	(802)
Change in Other Noncurrent Liabilities	1,872	1,204
Changes in Components of Working Capital:		
Accounts Receivable, Net	33,334	6,754
Fuel, Materials and Supplies	(2,704)	2,439
Accounts Payable	(7,212)	(11,227)
Taxes Accrued	(10,912)	8,535
Customer Deposits	(426)	305
Interest Accrued	(1,672)	(1,962)
Other Current Assets	4,361	(5,478)
Other Current Liabilities	(2,270)	(2,309)
Net Cash Flows From Operating Activities	20,831	12,403
INVESTING ACTIVITIES		
Construction Expenditures	(10,092)	(7,971)
Change in Other Cash Deposits, Net	-	581
Proceeds from Sale of Assets	250	-
Net Cash Flows Used For Investing Activities	(9,842)	(7,390)
FINANCING ACTIVITIES		
Retirement of Long-term Debt	-	(24,036)
Changes in Advances to/from Affiliates, Net	(1,232)	21,603
Dividends Paid on Common Stock	(9,427)	(2,000)
Dividends Paid on Cumulative Preferred Stock	(26)	(26)
Net Cash Flows Used For Financing Activities	(10,685)	(4,459)
Net Increase in Cash and Cash Equivalents	304	554
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ 304	$ 554

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $6,236,000 and $7,568,000 and for income taxes was $17,447,000 and $(412,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $137,000 and $25,000, 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.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income (in millions)

First Quarter of 2004 Net Income		$ 65
Changes in Gross Margin:		
Retail Margins	(32)	
Off-system Sales	15	
Transmission Revenues	(8)	
Other Revenues	4	
Total Change in Gross Margin		(21)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(8)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	(3)	
Interest Charges	1	
Total Change in Operating Expenses and Other		(13)
Income Tax Expense		16
First Quarter of 2005 Net Income		$ 47

Net Income decreased $18 million to $47 million in the first quarter of 2005. The key drivers of the decrease were a $21 million decrease in gross margin and a $13 million net increase in operating expenses and other partially offset by a $16 million decrease in income taxes.

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

- Retail Margins decreased by $32 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak that was established in December 2004 resulting in a $16 million increase in capacity settlement payments under the Interconnection Agreement. In addition, there was a $16 million increase in under-recovered fuel.
- Margins from Off-system Sales for 2005 increased by $15 million in comparison to 2004 primarily due to higher sales volumes primarily caused by our new peak established in December 2004 as well as higher optimization activity.
- Margins from Transmission Revenues decreased $8 million primarily due to the elimination of $12 million of revenues related to through and out rates partially offset by an increase of $4 million in unbundled transmission revenues due to the addition of SECA rates as mandated by the FERC.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $8 million primarily due to increases in plant maintenance, removal costs and PJM scheduling fees partially offset by the settlement and cancellation of the corporate owned life insurance policy in February 2005.
- Nonoperating Income and Expenses, Net decreased $3 million primarily due to unfavorable results from risk management activities.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 34.3% and 38.0%, 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 temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences including COLI and 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
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for the three months ended March 31, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ 536	$ 4,561
Cash flows from (used for):		
Operating activities	94,570	180,602
Investing activities	(151,768)	(49,024)
Financing activities	57,875	(131,630)
Net increase (decrease) in cash and cash equivalents	677	(52)
Cash and cash equivalents at end of period	$ 1,213	$ 4,509

Operating Activities

Our net cash flows from operating activities were $95 million in 2005. We produced income of $47 million during the period and noncash expense items of $50 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items.

Our net cash flows from operating activities were $181 million in 2004. We produced income of $65 million during the period and had a noncash expense item of $48 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had one significant item; a decrease in Accounts Receivable of $55 million due to settlements of affiliated receivables at December 2003 as well as a lower MLR share of physical off-system sales from December 2003 to March 2004.

Investing Activities

Cash flows used for investing activities during 2005 and 2004 primarily reflect our construction expenditures of $139 million and $90 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2005 and 2004, capital projects for transmission expenditures are primarily related to the Jacksons Ferry-Wyoming 765 kV line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on Amos Unit 1 and the flue gas desulfurization project at the Mountaineer Plant. For the remainder of 2005, we expect our Construction Expenditures to be approximately $559 million.

Financing Activities

In 2005, we issued Senior Unsecured Notes of $200 million with an interest rate of 4.95% and received a capital contribution from our parent of $100 million. In addition, we repaid $211 million of advances from affiliates and advanced $29 million to our affiliates.

In 2004, we retired $40 million of Installment Purchase Contracts with an interest rate of 5.45%. In addition, we repaid $66 million of advances from affiliates and paid $25 million in common stock dividends.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$200,000	4.95	2015

Retirements

None

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	54,124
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(9,032)
Fair Value of New Contracts When Entered During the Period (b)		305
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		15,325
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		4,596
Total MTM Risk Management Contract Net Assets		65,318
Net Cash Flow and Fair Value Hedge Contracts (f)		(17,544)
DETM Assignment (g)		(21,570)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	26,204

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(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 in 2005.
(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) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 120,952	$ 5,972	$ -	$ 126,924
Noncurrent Assets	144,582	719	-	145,301
Total MTM Derivative Contract Assets	265,534	6,691	-	272,225
Current Liabilities	(111,460)	(21,412)	(8,829)	(141,701)
Noncurrent Liabilities	(88,756)	(2,823)	(12,741)	(104,320)
Total MTM Derivative Contract Liabilities	(200,216)	(24,235)	(21,570)	(246,021)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 65,318	$ (17,544)	$ (21,570)	$ 26,204

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted – Exchange Traded Contracts	$ (9,621)	$ 3,704	$ 7,671	$ -	$ -	$ -	$ 1,754
Prices Provided by Other External Sources - OTC Broker Quotes (a)	18,437	19,928	13,827	6,359	-	-	58,551
Prices Based on Models and Other Valuation Methods (b)	(351)	(10,244)	(7,397)	5,262	9,398	8,345	5,013
Total	$ 8,465	$ 13,388	$ 14,101	$ 11,621	$ 9,398	$ 8,345	$ 65,318

(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) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $8 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value 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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)
Changes in Fair Value (a)	(7,165)	-	2,996	(4,169)
Reclassifications from AOCI to Net Income (b)	(3,817)	2	274	(3,541)
Ending Balance March 31, 2005	$ (8,560)	$ (174)	$ (8,300)	$ (17,034)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $8,899 thousand loss.

Credit Risk

Counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$629	$1,391	$682	$411	$577	$1,883	$812	$277

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 $114 million and $99 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 504,141	$ 473,225
Sales to AEP Affiliates	52,938	53,882
TOTAL	557,079	527,107
OPERATING EXPENSES		
Fuel for Electric Generation	113,381	110,711
Purchased Electricity for Resale	28,233	16,644
Purchased Electricity from AEP Affiliates	126,963	90,487
Other Operation	71,008	68,742
Maintenance	47,190	41,320
Depreciation and Amortization	49,959	47,913
Taxes Other Than Income Taxes	24,039	23,453
Income Taxes	26,242	40,440
TOTAL	487,015	439,710
OPERATING INCOME	70,064	87,397
Nonoperating Income	3,487	5,547
Nonoperating Expenses	4,563	2,533
Nonoperating Income Tax Credit	1,883	362
Interest Charges	24,199	25,437
NET INCOME	46,672	65,336
Preferred Stock Dividend Requirements, Including Capital Stock Expense	797	823
EARNINGS APPLICABLE TO COMMON STOCK	$ 45,875	$ 64,513

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 260,458	$ 719,899	$ 408,718	$ (52,088)	$ 1,336,987
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		623	(623)		-
TOTAL					1,311,787
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,642				(3,050)	(3,050)
NET INCOME			65,336		65,336
TOTAL COMPREHENSIVE INCOME					62,286
MARCH 31, 2004	$ 260,458	$ 720,522	$ 448,231	$ (55,138)	$ 1,374,073
DECEMBER 31, 2004	$ 260,458	$ 722,314	$ 508,618	$ (81,672)	$ 1,409,718
Capital Contribution from Parent		100,000			100,000
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		597	(597)		-
TOTAL					1,509,518
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,151				(7,710)	(7,710)
NET INCOME			46,672		46,672
TOTAL COMPREHENSIVE INCOME					38,962
MARCH 31, 2005	$ 260,458	$ 822,911	$ 554,493	$ (89,382)	$ 1,548,480

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 2,525,139	$ 2,502,273
Transmission	1,257,336	1,255,390
Distribution	2,088,544	2,070,377
General	294,211	302,474
Construction Work in Progress	473,066	399,116
Total	6,638,296	6,529,630
Accumulated Depreciation and Amortization	2,458,894	2,443,218
TOTAL - NET	4,179,402	4,086,412
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	20,834	20,378
Other Investments	13,029	18,775
TOTAL	33,863	39,153
CURRENT ASSETS		
Cash and Cash Equivalents	1,213	536
Other Cash Deposits	14,995	1,133
Advance to Affiliates	29,054	-
Accounts Receivable:		
Customers	151,080	126,422
Affiliated Companies	126,573	140,950
Accrued Unbilled Revenues	34,147	51,427
Miscellaneous	1,311	1,264
Allowance for Uncollectible Accounts	(1,722)	(5,561)
Risk Management Assets	126,924	81,811
Fuel	52,058	45,756
Materials and Supplies	45,106	45,644
Margin Deposits	15,800	8,329
Prepayments and Other	17,280	12,192
TOTAL	613,819	509,903
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	343,652	343,415
Transition Regulatory Assets	24,406	25,467
Unamortized Loss on Reacquired Debt	17,356	18,157
Other	52,448	36,368
Long-term Risk Management Assets	145,301	81,245
Emission Allowances	43,530	38,931
Deferred Property Taxes	40,423	37,071
Deferred Charges and Other	10,880	23,796
TOTAL	677,996	604,450
TOTAL ASSETS	$ 5,505,080	$ 5,239,918

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	822,911	722,314
Retained Earnings	554,493	508,618
Accumulated Other Comprehensive Income (Loss)	(89,382)	(81,672)
Total Common Shareholder's Equity	1,548,480	1,409,718
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders' Equity	1,566,264	1,427,502
Long-term Debt – Nonaffiliated	1,352,724	1,254,588
TOTAL	2,918,988	2,682,090
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	630,010	530,010
Advances from Affiliates	-	211,060
Accounts Payable:		
General	176,933	130,710
Affiliated Companies	71,712	76,314
Risk Management Liabilities	141,701	89,136
Taxes Accrued	69,088	90,404
Interest Accrued	38,041	21,076
Customer Deposits	56,379	42,822
Obligations Under Capital Leases	6,577	6,742
Other	50,191	56,645
TOTAL	1,240,632	1,254,919
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	858,067	852,536
Regulatory Liabilities:		
Asset Removal Costs	92,337	95,763
Over-recovery of Fuel Cost	61,163	57,843
Deferred Investment Tax Credits	29,248	30,382
Unrealized Gain on Forward Commitments	35,685	23,270
Employee Benefits and Pension Obligations	110,725	130,530
Long-term Risk Management Liabilities	104,320	57,349
Asset Retirement Obligations	25,101	24,626
Obligations Under Capital Leases	12,000	13,136
Deferred Credits	16,814	17,474
TOTAL	1,345,460	1,302,909
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,505,080	$ 5,239,918

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 46,672	$ 65,336
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	49,959	47,913
Accretion Expense	474	425
Deferred Income Taxes	9,445	14,742
Deferred Investment Tax Credits	(1,134)	(1,089)
Deferred Property Taxes	(3,352)	(3,097)
Pension Contributions	(19,937)	-
Pension and Postemployment Benefit Reserves	96	(883)
Mark-to-Market of Risk Management Contracts	(13,360)	(8,015)
Over/Under Fuel Recovery	3,320	2,499
Change in Other Noncurrent Assets	(9,809)	(14,803)
Change in Other Noncurrent Liabilities	(1,442)	9,969
Changes in Components of Working Capital:		
Accounts Receivable, Net	3,113	55,191
Fuel, Materials and Supplies	(5,764)	(14,507)
Accounts Payable	41,621	(25,777)
Taxes Accrued	(21,316)	26,910
Customer Deposits	13,557	10,984
Interest Accrued	16,965	17,869
Other Current Assets	(7,918)	3,748
Other Current Liabilities	(6,620)	(6,813)
Net Cash Flows From Operating Activities	94,570	180,602
INVESTING ACTIVITIES		
Construction Expenditures	(138,612)	(89,583)
Change in Other Cash Deposits, Net	(13,862)	40,559
Proceeds from Sale of Assets	706	-
Net Cash Flows Used For Investing Activities	(151,768)	(49,024)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	198,189	-
Retirement of Long-term Debt	-	(40,002)
Capital Contribution from Parent	100,000	-
Changes in Advances to/from Affiliates, Net	(240,114)	(66,428)
Dividends Paid on Common Stock	-	(25,000)
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Net Cash Flows From (Used For) Financing Activities	57,875	(131,630)
Net Increase (Decrease) in Cash and Cash Equivalents	677	(52)
Cash and Cash Equivalents at Beginning of Period	536	4,561
Cash and Cash Equivalents at End of Period	$ 1,213	$ 4,509

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $5,842,000 and $5,214,000 and for income taxes was $38,845,000 and $1,599,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $460,000 and $360,000, respectively.

See Notes to Respective Financial Statements 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.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$	45
Changes in Gross Margin:			
Retail Margins	(5)		
Transmission Revenues	(6)		
Off-system Sales	1		
Other Revenues	(2)		
Total Change in Gross Margin			(12)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	10		
Depreciation and Amortization	(1)		
Taxes Other Than Income Taxes	(1)		
Nonoperating Income and Expenses, Net	3		
Total Change in Operating Expenses and Other			11
Income Tax Expense			3
First Quarter of 2005 Net Income		$	47

Net Income remained relatively flat in the first quarter of 2005.

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

- Retail Margins were $5 million less than the prior period primarily due to lower usage by residential and industrial customers.
- Margins from Transmission Revenues decreased $6 million primarily due to the loss of through and out rates as mandated by the FERC. The decrease was partially offset by an increase in unbundled transmission revenues due to the addition of SECA rates.

Operating Expenses and Other decreased between years as follows:

- Other Operation and Maintenance expenses decreased $10 million primarily due to lower expenditures than estimated for storm expenses from the major ice storm in December 2004, the settlement and cancellation of the corporate owned life insurance policy in February 2005 and the establishment of a regulatory asset for PJM administrative fees.
- Nonoperating Income and Expenses, Net increased $3 million primarily due to an establishment of a regulatory asset for carrying costs on environmental capital expenditures offset by lower margins on risk management activities.

Income Tax

The effective tax rates for the first quarter of 2005 and 2004 were 31.9% and 36.0%, 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 temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to a decrease in state and local income taxes and changes in permanent differences including COLI.

Financial Condition

Credit Ratings

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

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

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2005.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	30,919
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(6,292)
Fair Value of New Contracts When Entered During the Period (b)		268
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		8,528
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		33,423
Net Cash Flow Hedge Contracts (f)		(6,739)
DETM Assignment (g)		(11,038)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	15,646

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(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 in 2005.

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

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 61,895	$ 2,935	$ -	$ 64,830
Noncurrent Assets	73,988	368	-	74,356
Total MTM Derivative Contract Assets	135,883	3,303	-	139,186
Current Liabilities	(57,040)	(9,114)	(4,518)	(70,672)
Noncurrent Liabilities	(45,420)	(928)	(6,520)	(52,868)
Total MTM Derivative Contract Liabilities	(102,460)	(10,042)	(11,038)	(123,540)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,423	$ (6,739)	$ (11,038)	$ 15,646

(a) Does not include Cash Flow Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted – Exchange Traded Contracts	$ (4,923)	$ 1,895	$ 3,925	$ -	$ -	$ -	$ 897
Prices Provided by Other External Sources - OTC Broker Quotes (a)	9,435	10,197	7,076	3,254	-	-	29,962
Prices Based on Models and Other Valuation Methods (b)	(181)	(5,242)	(3,785)	2,692	4,810	4,270	2,564
Total	$ 4,331	$ 6,850	$ 7,216	$ 5,946	$ 4,810	$ 4,270	$ 33,423

(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) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $4.1 million of this mark-to-market value is in 2010.

(d) 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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 1,393
Changes in Fair Value (a)	(3,821)
Reclassifications from AOCI to Net Income (b)	(1,953)
Ending Balance March 31, 2005	$ (4,381)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $4,017 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Energy and Gas Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$322	$712	$349	$210	$332	$1,083	$467	$160

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 $55 million and $48 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 340,156	$ 344,078
Sales to AEP Affiliates	24,093	18,619
TOTAL	364,249	362,697
OPERATING EXPENSES		
Fuel for Electric Generation	61,352	41,637
Fuel From Affiliates for Electric Generation	-	8,848
Purchased Electricity for Resale	9,203	4,681
Purchased Electricity from AEP Affiliates	79,775	81,715
Other Operation	48,768	57,873
Maintenance	15,384	16,826
Depreciation and Amortization	38,198	36,818
Taxes Other Than Income Taxes	36,162	35,326
Income Taxes	20,422	24,465
TOTAL	309,264	308,189
OPERATING INCOME	54,985	54,508
Nonoperating Income	7,968	5,078
Nonoperating Expenses	756	734
Nonoperating Income Tax Expense	1,817	919
Interest Charges	12,912	12,814
NET INCOME	47,468	45,119
Preferred Stock Dividend Requirements including Capital Stock Expense	254	254
EARNINGS APPLICABLE TO COMMON STOCK	$ 47,214	$ 44,865

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

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 41,026	$ 576,400	$ 326,782	$ (46,327)	$ 897,881
Common Stock Dividends			(31,250)		(31,250)
Capital Stock Expense		254	(254)		-
TOTAL					866,631
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,028				(1,910)	(1,910)
NET INCOME			45,119		45,119
TOTAL COMPREHENSIVE INCOME					43,209
MARCH 31, 2004	$ 41,026	$ 576,654	$ 340,397	$ (48,237)	$ 909,840
DECEMBER 31, 2004	$ 41,026	$ 577,415	$ 341,025	$ (60,816)	$ 898,650
Common Stock Dividends			(28,500)		(28,500)
Capital Stock Expense		254	(254)		-
TOTAL					870,150
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,109				(5,774)	(5,774)
NET INCOME			47,468		47,468
TOTAL COMPREHENSIVE INCOME					41,694
MARCH 31, 2005	$ 41,026	$ 577,669	$ 359,739	$ (66,590)	$ 911,844

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,664,673	$ 1,658,552
Transmission	439,747	432,714
Distribution	1,316,498	1,300,252
General	164,314	167,985
Construction Work in Progress	127,079	131,743
Total	3,712,311	3,691,246
Accumulated Depreciation and Amortization	1,487,677	1,471,950
TOTAL - NET	2,224,634	2,219,296
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	21,648	22,322
Other Investments	4,115	5,147
TOTAL	25,763	27,469
CURRENT ASSETS		
Cash and Cash Equivalents	671	25
Other Cash Deposits	7,158	33
Advances to Affiliates	59,416	141,550
Accounts Receivable:		
Customers	46,277	41,130
Affiliated Companies	58,598	72,854
Accrued Unbilled Revenues	14,510	19,580
Miscellaneous	667	1,145
Allowance for Uncollectible Accounts	(76)	(674)
Fuel	27,255	34,026
Materials and Supplies	36,379	37,137
Risk Management Assets	64,830	46,631
Margin Deposits	8,229	4,848
Prepayments and Other	14,883	11,499
TOTAL	338,797	409,784
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	16,991	16,481
Transition Regulatory Assets	148,285	156,676
Unamortized Loss on Reacquired Debt	12,963	13,155
Other	44,147	25,691
Long-term Risk Management Assets	74,356	46,735
Deferred Property Taxes	48,816	64,754
Deferred Charges and Other	45,125	49,855
TOTAL	390,683	373,347
TOTAL ASSETS	$ 2,979,877	$ 3,029,896

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	577,669	577,415
Retained Earnings	359,739	341,025
Accumulated Other Comprehensive Income (Loss)	(66,590)	(60,816)
Total Common Shareholder's Equity	911,844	898,650
Preferred Stock – No Shares Outstanding	-	-
Authorized – 2,500,000 shares at $100 par value		
Authorized – 7,000,000 shares at $25 par value		
Total Shareholder's Equity	911,844	898,650
Long-term Debt:		
Nonaffiliated	851,691	851,626
Affiliated	100,000	100,000
Total Long-term Debt	951,691	951,626
TOTAL	1,863,535	1,850,276
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	36,000	36,000
Accounts Payable:		
General	52,093	63,606
Affiliated Companies	35,523	45,745
Customer Deposits	31,063	24,890
Taxes Accrued	133,376	195,284
Interest Accrued	8,049	16,320
Risk Management Liabilities	70,672	42,172
Obligations Under Capital Leases	3,590	3,854
Other	16,485	24,338
TOTAL	386,851	452,209
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	459,333	464,545
Regulatory Liabilities:		
Asset Removal Costs	104,889	103,104
Deferred Investment Tax Credits	27,272	27,933
Employee Benefits and Pension Obligations	49,801	62,778
Long-term Risk Management Liabilities	52,868	32,731
Obligations Under Capital Leases	8,060	8,660
Asset Retirement Obligations	11,799	11,585
Deferred Credits and Other	15,469	16,075
TOTAL	729,491	727,411
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,979,877	$ 3,029,896

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 47,468	$ 45,119
Adjustments to Reconcile Net Income to Net Cash Flows From (Used For) Operating Activities:		
Depreciation and Amortization	38,198	36,818
Deferred Income Taxes	(2,613)	7,726
Deferred Investment Tax Credits	(661)	(752)
Deferred Property Taxes	15,938	15,011
Pension and Postemployment Benefit Reserves	(366)	(1,311)
Mark-to-Market of Risk Management Contracts	(5,120)	(6,766)
Pension Contributions	(12,611)	-
Gain on Sale of Assets	(1,130)	(1,786)
Change in Other Noncurrent Assets	(17,816)	(4,878)
Change in Other Noncurrent Liabilities	263	(2,054)
Changes in Components of Working Capital:		
Accounts Receivable, Net	14,059	23,091
Fuel, Materials and Supplies	7,529	(8,556)
Accounts Payable	(21,735)	(10,668)
Taxes Accrued	(61,908)	(7,718)
Customer Deposits	6,173	6,047
Interest Accrued	(8,271)	(6,583)
Other Current Assets	(3,926)	(831)
Other Current Liabilities	(8,117)	(1,058)
Net Cash Flows From (Used For) Operating Activities	(14,646)	80,851
INVESTING ACTIVITIES		
Construction Expenditures	(33,042)	(27,129)
Change in Other Cash Deposits, Net	(7,125)	7
Proceeds from Sale of Assets	1,825	2,105
Net Cash Flows Used For Investing Activities	(38,342)	(25,017)
FINANCING ACTIVITIES		
Changes in Advances to/from Affiliates, Net	82,134	(24,575)
Dividends Paid on Common Stock	(28,500)	(31,250)
Net Cash Flows From (Used For) Financing Activities	53,634	(55,825)
Net Increase in Cash and Cash Equivalents	646	9
Cash and Cash Equivalents at Beginning of Period	25	3,377
Cash and Cash Equivalents at End of Period	$ 671	$ 3,386

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $21,898,000 and $18,971,000 and for income taxes was $57,037,000 and $(3,806,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $160,000 and $67,000 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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.

INDIANA MICHIGAN POWER COMPANY

AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 43
Changes in Gross Margin:		
Retail Margins	5	
Transmission Revenues	(7)	
Off-system Sales	2	
Other Revenues	1	
Total Change in Gross Margin		1
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(6)	
Taxes Other Than Income Taxes	(2)	
Nonoperating Income and Expenses, Net	(4)	
Interest Charges	2	
Total Change in Operating Expenses and Other		(10)
Income Tax Expense		6
First Quarter of 2005 Net Income		$ 40

Net Income decreased $3 million to $40 million in the first quarter of 2005. The key driver of the decrease was a $10 million net increase in operating and other expenses partially offset by a $6 million decrease in income taxes.

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

- Retail Margins increased $5 million primarily due to an $11 million increase in capacity settlement payments under the Interconnection Agreement related to the increase in an affiliate's peak partially offset by a $6 million increase in unrecovered fuel costs.
- Margins from Transmission Revenues decreased $7 million primarily due to the loss of through and out rates as mandated by the FERC.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $6 million primarily due to a $12 million increase in distribution maintenance mainly for storm damage expenses partially offset by the settlement and cancellation of the corporate owned life insurance policy in February 2005.
- Taxes Other Than Income Taxes increased $2 million primarily due to a $1 million increase in property taxes and a $1 million increase in payroll-related taxes.
- Nonoperating Income and Expenses, Net declined $4 million reflecting lower margins on risk management transactions.
- Interest Charges decreased $2 million primarily due to lower long-term debt interest expense resulting from lower debt balances and lower interest rates.

Income Tax

The effective tax rates for the first quarter of 2005 and 2004 were 33.2% and 37.6%, 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 temporary 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 and local income taxes and changes in permanent differences including COLI.

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

Cash Flow

Cash flows for the first three months of 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ 465	$ 3,899
Cash flows from (used for):		
Operating activities	42,077	181,789
Investing activities	(60,537)	(35,282)
Financing activities	18,530	(147,177)
Net increase (decrease) in cash and cash equivalents	70	(670)
Cash and cash equivalents at end of period	$ 535	$ 3,229

Operating Activities

Our net cash flows from operating activities were $42 million for the first three months of 2005. We produced income of $40 million during the period including noncash expense items of $54 million for depreciation, amortization and accretion. 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 were a $15 million contribution to our pension trust, an $81 million federal income tax payment and a net change in accounts receivable and payable of $11 million.

Our net cash flows from operating activities were $182 million in 2004. We produced Net Income of $43 million during the period and noncash expense items of $52 million for Depreciation, Amortization and Accretion. The other changes in assets and liabilities represent items that had a 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 activity in working capital relates to a number of items; the most significant relates to Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

Cash flows used for investing activities during 2005 were $61 million due to construction expenditures and a deposit to purchase emissions allowances. Construction expenditures were primarily incurred for nuclear generation, transmission and distribution assets to upgrade or replace equipment and improve reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $270 million.

Our cash flows used for investing activities were $35 million in 2004 for construction.

Financing Activities

During the first quarter of 2005, we used cash of $61 million to retire preferred stock and $21 million to pay common dividends. These activities and our Construction Expenditures were supported by additional borrowing from the Money Pool of $101 million. There were no long-term debt issuances or retirements during the first quarter of 2005.

Our cash flows used for financing activities were $147 million in 2004. We used cash from operations to repay short-term debt and pay common dividends.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Off-Balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our 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 in the normal course of business. Our off-balance sheet arrangements have not changed significantly since year-end. For complete information on our off-balance sheet arrangements see "Off-balance Sheet Arrangements" in "Management's Financial Discussion and Analysis" section of our 2004 Annual Report.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 34,573
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(74)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	(233)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	3,105
Total MTM Risk Management Contract Net Assets	37,371
Net Cash Flow and Fair Value Hedge Contracts (f)	(7,971)
DETM Assignment (g)	(12,342)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$ 17,058

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(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 in 2005.
(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) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets As of March 31, 2005 (in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 69,207	$ 3,282	$ -	$ 72,489
Noncurrent Assets	82,728	412	-	83,140
Total MTM Derivative Contract Assets	151,935	3,694	-	155,629
Current Liabilities	(63,778)	(10,333)	(5,052)	(79,163)
Noncurrent Liabilities	(50,786)	(1,332)	(7,290)	(59,408)
Total MTM Derivative Contract Liabilities	(114,564)	(11,665)	(12,342)	(138,571)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 37,371	$ (7,971)	$ (12,342)	$ 17,058

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted – Exchange Traded Contracts	$ (5,505)	$ 2,119	$ 4,389	$ -	$ -	$ -	$ 1,003
Prices Provided by Other External Sources - OTC Broker Quotes (a)	10,549	11,402	7,912	3,638	-	-	33,501
Prices Based on Models and Other Valuation Methods (b)	(202)	(5,861)	(4,233)	3,010	5,378	4,775	2,867
Total	$ 4,842	$ 7,660	$ 8,068	$ 6,648	$ 5,378	$ 4,775	$ 37,371

(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) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $4.6 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value 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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)
Changes in Fair Value (a)	(4,272)	-	(4,272)
Reclassifications from AOCI to Net Income (b)	(2,184)	143	(2,041)
Ending Balance March 31, 2005	$ (4,898)	$ (5,491)	$ (10,389)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $5,062 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$360	$796	$390	$235	$371	$1,211	$522	$178

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 $53 million at both March 31, 2005 and December 31, 2004. We would not expect to liquidate our entire portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 361,592	$ 353,822
Sales to AEP Affiliates	80,551	57,645
TOTAL	442,143	411,467
OPERATING EXPENSES		
Fuel for Electric Generation	77,824	64,041
Purchased Electricity for Resale	11,272	6,363
Purchased Electricity from AEP Affiliates	74,009	63,128
Other Operation	90,976	100,850
Maintenance	54,322	38,042
Depreciation and Amortization	42,745	42,715
Taxes Other Than Income Taxes	17,507	15,216
Income Taxes	19,934	24,299
TOTAL	388,589	354,654
OPERATING INCOME	53,554	56,813
Nonoperating Income	17,497	20,588
Nonoperating Expenses	16,013	14,851
Nonoperating Income Tax Expense (Credit)	(237)	1,613
Interest Charges	15,606	17,929
NET INCOME	39,669	43,008
Preferred Stock Dividend Requirements including Capital Stock Expense	118	118
EARNINGS APPLICABLE TO COMMON STOCK	$ 39,551	$ 42,890

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 56,584	$ 858,694	$ 187,875	$ (25,106)	$ 1,078,047
Common Stock Dividends			(29,646)		(29,646)
Preferred Stock Dividends			(84)		(84)
Capital Stock Expense		34	(34)		-
TOTAL					1,048,317
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,127				(2,093)	(2,093)
NET INCOME			43,008		43,008
TOTAL COMPREHENSIVE INCOME					40,915
MARCH 31, 2004	$ 56,584	$ 858,728	$ 201,119	$ (27,199)	$ 1,089,232
DECEMBER 31, 2004	$ 56,584	$ 858,835	$ 221,330	$ (45,251)	$ 1,091,498
Common Stock Dividends			(21,000)		(21,000)
Preferred Stock Dividends			(85)		(85)
Capital Stock Expense		33	(33)		-
TOTAL					1,070,413
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,400				(6,313)	(6,313)
NET INCOME			39,669		39,669
TOTAL COMPREHENSIVE INCOME					33,356
MARCH 31, 2005	$ 56,584	$ 858,868	$ 239,881	$ (51,564)	$ 1,103,769

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 3,123,688	$ 3,122,883
Transmission	1,008,687	1,009,551
Distribution	1,005,142	990,826
General (including nuclear fuel)	278,890	275,622
Construction Work in Progress	183,623	163,515
Total	5,600,030	5,562,397
Accumulated Depreciation and Amortization	2,629,388	2,603,479
TOTAL - NET	2,970,642	2,958,918
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,079,926	1,053,439
Nonutility Property, Net	49,731	50,440
Other Investments	13,251	21,848
TOTAL	1,142,908	1,125,727
CURRENT ASSETS		
Cash and Cash Equivalents	535	465
Other Cash Deposits	8,005	46
Advances to Affiliates	-	5,093
Accounts Receivable:		
Customers	61,822	62,608
Affiliated Companies	101,537	124,134
Miscellaneous	4,346	4,339
Allowance for Uncollectible Accounts	(76)	(187)
Fuel	21,219	27,218
Materials and Supplies	104,886	103,342
Risk Management Assets	72,489	52,141
Margin Deposits	9,184	5,400
Prepayments and Other	15,242	10,541
TOTAL	399,189	395,140
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	140,123	147,167
Incremental Nuclear Refueling Outage Expenses, Net	38,727	44,244
Unamortized Loss on Reacquired Debt	20,699	21,039
DOE Decontamination Fund	12,928	14,215
Other	48,426	31,015
Long-term Risk Management Assets	83,140	52,256
Emission Allowances	28,024	27,093
Deferred Property Taxes	31,461	22,372
Deferred Charges and Other Assets	18,381	28,955
TOTAL	421,909	388,356
TOTAL ASSETS	$ 4,934,648	$ 4,868,141

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
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	858,868	858,835
Retained Earnings	239,881	221,330
Accumulated Other Comprehensive Income (Loss)	(51,564)	(45,251)
Total Common Shareholder's Equity	1,103,769	1,091,498
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Total Shareholders' Equity	1,111,853	1,099,582
Long-term Debt	1,314,137	1,312,843
TOTAL	2,425,990	2,412,425
CURRENT LIABILITIES		
Cumulative Preferred Stock Due Within One Year	-	61,445
Advances from Affiliates	95,967	-
Accounts Payable:		
General	92,019	91,472
Affiliated Companies	38,599	51,066
Customer Deposits	34,117	29,366
Taxes Accrued	76,868	123,159
Interest Accrued	22,072	12,465
Risk Management Liabilities	79,163	47,174
Obligations Under Capital Leases	5,730	6,124
Other	74,372	70,237
TOTAL	518,907	492,508
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	304,460	315,730
Regulatory Liabilities:		
Asset Removal Costs	281,382	280,054
Deferred Investment Tax Credits	80,970	82,802
Excess ARO for Nuclear Decommissioning	259,825	245,175
Unrealized Gain on Forward Commitments	48,972	35,534
Other	30,832	33,695
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	65,545	66,472
Long-term Risk Management Liabilities	59,408	36,815
Obligations Under Capital Leases	40,380	44,608
Asset Retirement Obligations	723,433	711,769
Employee Benefits and Pension Obligations	55,999	70,027
Deferred Credits and Other	38,545	40,527
TOTAL	1,989,751	1,963,208
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 4,934,648	$ 4,868,141

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 Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 39,669	$ 43,008
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	42,745	42,715
Accretion Expense	11,664	9,698
Amortization, net of Deferrals of Incremental Nuclear Refueling Outage Expenses	5,517	13,179
Deferred Income Taxes	(876)	1,895
Deferred Investment Tax Credits	(1,832)	(1,832)
Deferred Property Taxes	(9,089)	(7,959)
Pension Contributions	(15,350)	-
Mark-to-Market of Risk Management Contracts	(5,722)	(7,396)
Change in Other Noncurrent Assets	(1,214)	(7,341)
Change in Other Noncurrent Liabilities	(5,972)	8,960
Changes in Components of Working Capital:		
Accounts Receivable, Net	23,265	52,625
Fuel, Materials and Supplies	4,455	(7,335)
Accounts Payable	(11,920)	(29,218)
Taxes Accrued	(46,291)	37,754
Customer Deposits	4,751	8,873
Interest Accrued	9,607	5,007
Rent Accrued – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(5,072)	1,006
Other Current Liabilities	(14,722)	(314)
Net Cash Flows From Operating Activities	42,077	181,789
INVESTING ACTIVITIES		
Construction Expenditures	(52,749)	(35,244)
Change in Other Cash Deposits, Net	(7,959)	(38)
Proceeds from Sale of Assets	171	-
Net Cash Flows Used For Investing Activities	(60,537)	(35,282)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(61,445)	(2,000)
Changes in Advances to/from Affiliates, Net	101,060	(115,447)
Dividends Paid on Common Stock	(21,000)	(29,646)
Dividends Paid on Cumulative Preferred Stock	(85)	(84)
Net Cash Flows From (Used For) Financing Activities	18,530	(147,177)
Net Increase (Decrease) in Cash and Cash Equivalents	70	(670)
Cash and Cash Equivalents at Beginning of Period	465	3,899
Cash and Cash Equivalents at End of Period	$ 535	$ 3,229

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $5,035,000 and $12,007,000 and for income taxes was $82,338,000 and $(5,480,000) in 2005 and 2004, respectively. Noncash acquisitions under capital leases were $404,000 and $373,000 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 12
Changes in Gross Margin:		
Retail Margins	(4)	
Off-system Sales	4	
Transmission Revenues	(2)	
Other Revenues	(2)	
Total Change in Gross Margin		(4)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	-	
Depreciation and Amortization	-	
Taxes Other Than Income Taxes	-	
Nonoperating Income and Expenses, Net	-	
Interest Charges	-	
Total Change in Operating Expenses and Other		-
Income Tax Expense		2
First Quarter of 2005 Net Income		$ 10

Net Income decreased $2 million to $10 million in the first quarter of 2005. The key driver of the decrease was a $4 million decrease in gross margin partially offset by a $2 million decrease in income taxes.

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

- Retail Margins decreased by $4 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand established in both December 2004 and January 2005 resulting in a $4 million increase in capacity settlement payments under the Interconnection Agreement.
- Margins from Off-system Sales for 2005 increased by $4 million in comparison to 2004 primarily due to higher sales volumes as well as higher optimization activity.
- Margins from Transmission Revenues decreased $2 million primarily due to the elimination of $3 million of revenues related to through and out rates partially offset by an increase of $1 million in unbundled transmission revenues due to the addition of SECA rates as mandated by the FERC.
- Margins from Other Revenues decreased $2 million primarily due to a $3 million adjustment of the Demand Side Management Program regulatory asset in March 2005.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 29.1% and 35.3%, 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 temporary differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in various permanent and flow-through temporary differences and lower state and local income taxes.

Financial Condition

Credit Ratings

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

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

Financing Activity

Long-term debt issuances and retirements during the first three months of 2005 were:

Issuances

None

Retirements

Notes Payable-Affiliated of $20 million with an interest rate of 6.50% was retired on April 15, 2005.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	12,691
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(78)
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		276
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		2,655
Total MTM Risk Management Contract Net Assets		15,544
Net Cash Flow and Fair Value Hedge Contracts (f)		(3,480)
DETM Assignment (g)		(5,133)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	6,931

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(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 in 2005.
(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) "Changes 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 and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Balance Sheets As of March 31, 2005 (in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 28,786	$ 1,552	$ -	$ 30,338
Noncurrent Assets	34,410	171	-	34,581
Total MTM Derivative Contract Assets	63,196	1,723	-	64,919
Current Liabilities	(26,528)	(4,239)	(2,101)	(32,868)
Noncurrent Liabilities	(21,124)	(964)	(3,032)	(25,120)
Total MTM Derivative Contract Liabilities	(47,652)	(5,203)	(5,133)	(57,988)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,544	$ (3,480)	$ (5,133)	$ 6,931

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted – Exchange Traded Contracts	$ (2,290)	$ 882	$ 1,826	$ -	$ -	$ -	$ 418
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4,388	4,743	3,291	1,514	-	-	13,936
Prices Based on Models and Other Valuation Methods (b)	(88)	(2,438)	(1,760)	1,253	2,237	1,986	1,190
Total	$ 2,010	$ 3,187	$ 3,357	$ 2,767	$ 2,237	$ 1,986	$ 15,544

(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) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $1.9 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value 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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate swap transactions in order to manage interest rate risk to existing floating rate debt. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 569	$ 244	$ 813
Changes in Fair Value (a)	(1,702)	-	(1,702)
Reclassifications from AOCI to Net Income (b)	(903)	(22)	(925)
Ending Balance March 31, 2005	$ (2,036)	$ 222	$ (1,814)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $1,782 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$150	$331	$162	$98	$135	$442	$191	$65

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 $16 million at both March 31, 2005 and December 31, 2004. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 115,660	$ 107,046
Sales to AEP Affiliates	12,189	6,612
TOTAL	127,849	113,658
OPERATING EXPENSES		
Fuel for Electric Generation	27,892	20,894
Purchased Electricity from AEP Affiliates	44,863	33,306
Other Operation	14,560	13,272
Maintenance	5,916	7,325
Depreciation and Amortization	11,152	10,859
Taxes Other Than Income Taxes	2,425	2,328
Income Taxes	4,008	6,460
TOTAL	110,816	94,444
OPERATING INCOME	17,033	19,214
Nonoperating Income	445	952
Nonoperating Expenses	171	1,313
Nonoperating Income Tax Expense (Credit)	52	(127)
Interest Charges	7,370	7,369
NET INCOME	$ 9,885	$ 11,611

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 50,450	$ 208,750	$ 64,151	$ (6,213)	$ 317,138
Common Stock Dividends			(6,250)		(6,250)
TOTAL					310,888
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $406				(754)	(754)
NET INCOME			11,611		11,611
TOTAL COMPREHENSIVE INCOME					10,857
MARCH 31, 2004	$ 50,450	$ 208,750	$ 69,512	$ (6,967)	$ 321,745
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$ 320,980
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,415				(2,627)	(2,627)
NET INCOME			9,885		9,885
TOTAL COMPREHENSIVE INCOME					7,258
MARCH 31, 2005	$ 50,450	$ 208,750	$ 80,440	$ (11,402)	$ 328,238

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

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 464,637	$ 462,641
Transmission	385,912	385,667
Distribution	442,925	438,766
General	58,979	57,929
Construction Work in Progress	14,702	16,544
Total	1,367,155	1,361,547
Accumulated Depreciation and Amortization	406,584	398,455
TOTAL – NET	960,571	963,092
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	5,437	5,438
Other Investments	351	422
TOTAL	5,788	5,860
CURRENT ASSETS		
Cash and Cash Equivalents	276	127
Other Cash Deposits	3,319	5
Advances to Affiliates	24,734	16,127
Accounts Receivable:		
Customers	24,674	22,130
Affiliated Companies	23,232	23,046
Accrued Unbilled Revenues	5,703	7,340
Miscellaneous	109	94
Allowance for Uncollectible Accounts	(9)	(34)
Fuel	8,111	6,551
Materials and Supplies	8,698	9,385
Risk Management Assets	30,338	19,845
Margin Deposits	3,760	1,960
Prepayments and Other	3,294	1,782
TOTAL	136,239	108,358
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	100,954	103,849
Other	22,875	14,558
Long-term Risk Management Assets	34,581	19,067
Emission Allowances	10,714	9,666
Deferred Property Taxes	5,408	7,036
Deferred Charges and Other	8,256	11,761
TOTAL	182,788	165,937
TOTAL ASSETS	$ 1,285,386	$ 1,243,247

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

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $50 par value per share:		
Authorized – 2,000,000 shares		
Outstanding – 1,009,000 shares	$ 50,450	$ 50,450
Paid-in Capital	208,750	208,750
Retained Earnings	80,440	70,555
Accumulated Other Comprehensive Income (Loss)	(11,402)	(8,775)
Total Common Shareholder's Equity	328,238	320,980
Long-term Debt:		
Nonaffiliated	427,375	428,310
Affiliated	80,000	80,000
Total Long-term Debt	507,375	508,310
TOTAL	835,613	829,290
CURRENT LIABILITIES		
Accounts Payable:		
General	23,975	20,080
Affiliated Companies	21,075	24,899
Risk Management Liabilities	32,868	17,205
Taxes Accrued	11,663	9,248
Interest Accrued	8,992	6,754
Customer Deposits	15,709	12,309
Obligations Under Capital Leases	1,458	1,561
Other	8,304	9,038
TOTAL	124,044	101,094
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	224,214	227,536
Regulatory Liabilities:		
Asset Removal Costs	29,214	28,232
Deferred Investment Tax Credits	6,430	6,722
Other Regulatory Liabilities	22,982	15,622
Employee Benefits and Pension Obligations	14,714	17,729
Long-term Risk Management Liabilities	25,120	13,484
Obligations Under Capital Leases	2,577	2,802
Deferred Credits	478	736
TOTAL	325,729	312,863
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,285,386	$ 1,243,247

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

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 9,885	$ 11,611
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	11,152	10,859
Deferred Income Taxes	988	3,442
Deferred Investment Tax Credits	(292)	(292)
Deferred Property Taxes	1,628	1,581
Pension Contributions	(3,045)	-
Pension and Postemployment Benefit Reserves	30	(377)
Mark-to-Market of Risk Management Contracts	(3,290)	(2,135)
Over/Under Fuel Recovery	(5,203)	(988)
Loss on Sale of Assets	-	1,051
Change in Other Noncurrent Assets	94	(7,219)
Change in Other Noncurrent Liabilities	4,413	8,274
Changes in Components of Working Capital:		
Accounts Receivable, Net	(1,133)	8,202
Fuel, Materials and Supplies	(873)	(2,772)
Accounts Payable	71	3,266
Taxes Accrued	2,415	5,027
Customer Deposits	3,400	2,564
Interest Accrued	2,238	1,970
Other Current Assets	(2,234)	798
Other Current Liabilities	(833)	(1,190)
Net Cash Flows From Operating Activities	19,411	43,672
INVESTING ACTIVITIES		
Construction Expenditures	(7,341)	(7,374)
Change in Other Cash Deposits, Net	(3,314)	(15)
Proceeds from Sale of Assets	-	1,538
Net Cash Flows Used For Investing Activities	(10,655)	(5,851)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Affiliated	-	20,000
Changes in Advances to/from Affiliates, Net	(8,607)	(51,238)
Dividends Paid on Common Stock	-	(6,250)
Net Cash Flows Used For Financing Activities	(8,607)	(37,488)
Net Increase in Cash and Cash Equivalents	149	333
Cash and Cash Equivalents at Beginning of Period	127	863
Cash and Cash Equivalents at End of Period	$ 276	$ 1,196

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $3,570,000 and $5,104,000 and for income taxes was $691,000 and $(833,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 were $126,000.

See Notes to Respective Financial Statements 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.

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ 80
Changes in Gross Margin:		
Retail Margins	(7)	
Transmission Revenues	(7)	
Off-system Sales	5	
Total Change in Gross Margin		(9)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	5	
Depreciation and Amortization	(2)	
Nonoperating Income and Expenses, Net	23	
Interest Charges	6	
Total Change in Operating Expenses and Other		32
Income Tax Expense		(4)
First Quarter of 2005 Net Income		$ 99

Net Income increased $19 million in the first quarter of 2005. The key driver of the increase was a $32 million net decrease in operating expenses and other partially offset by a $9 million decrease in gross margin.

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

- Retail Margins were $7 million less than the prior period primarily due to higher fuel costs.
- Margins from Transmission Revenues decreased $7 million primarily due to the loss of through and out rates as mandated by the FERC. The decrease was partially offset by an increase in unbundled transmission revenues due to the addition of SECA rates.
- Margins from Off-system Sales increased $5 million primarily due to favorable optimization activity and increased sales volumes.

Operating Expenses and Other changed between years as follows:

- Nonoperating Income and Expenses, Net increased $23 million primarily due to an establishment of a regulatory asset for carrying costs on environmental capital expenditures of $22 million as a result of the recent PUCO rate stabilization plan order.
- Interest Charges decreased by $6 million primarily due to refinancing debt maturities and optional redemptions with lower cost debt.
- Other Operation and Maintenance expenses decreased $5 million primarily due to the settlement and cancellation of the corporate owned life insurance policy of $7 million in February 2005, a decrease in administrative expenses of $4 million related to the Gavin Scrubber, the establishment of a regulatory asset for PJM administrative fees of $2 million and decreases in employee benefit expenses and administrative and support expenses offset by a $10 million increase in expense from a major ice storm in January 2005.

Income Tax

The effective tax rates for the first quarter of 2005 and 2004 were 33.1% and 36.0%, 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 temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences including COLI.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the three months ended March 31, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ 9,300	$ 7,233
Cash flows from (used for):		
Operating activities	74,821	125,131
Investing activities	(144,208)	2,187
Financing activities	61,170	(123,792)
Net increase (decrease) in cash and cash equivalents	(8,217)	3,526
Cash and cash equivalents at end of period	$ 1,083	$ 10,759

Operating Activities

Our net cash flows from operating activities were $74 million for the first three months of 2005. We produced income of $99 million during the period and a noncash expense item of $74 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital primarily relates to a $73 million decrease in Taxes Accrued due to a 2004 federal income tax payment made in the first quarter of 2005.

Our net cash flows from operating activities were $125 million for the first three months of 2004. We produced income of $80 million during the period and a noncash expense item of $72 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a 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 activity in working capital relates to a number of items; none of which were significant.

Investing Activities

Our net cash flows used for investing activities for the first three months of 2005 were $144 million primarily due to Construction Expenditures and a deposit to purchase emissions allowances. Construction expenditures were focused primarily on environmental upgrades, as well as projects to improve service reliability for transmission and distribution. For the remainder of 2005, we expect our Construction Expenditures to be approximately $632 million.

Our net cash flows from investing activities for the first three months of 2004 were $2 million. The change is primarily due to a cash deposit that we used to redeem $50 million of debt in January 2004 offset by construction expenditures.

Financing Activities

Our net cash flows from financing activities during the first three months of 2005 were $61 million primarily due to increased repayment of borrowings from the AEP Utility Money Pool.

Our net cash flows used for financing activities during the first three months of 2004 were $124 million primarily due to decreased repayments of borrowings from the AEP Utility Money Pool and dividend payments on Common Stock.

Financing Activity

In January 2005, we redeemed $5 million of 5.90% Cumulative Preferred Stock Subject to Mandatory Redemption. Additionally, long-term debt issuances and retirements during the three months ended March 31, 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$54,500	Variable	2029
Installment Purchase Contracts	54,500	Variable	2028
Installment Purchase Contracts	54,500	Variable	2028
Installment Purchase Contracts	54,500	Variable	2028

Retirements and Principal Payments

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contracts	$51,000	6.375	2029
Installment Purchase Contracts	51,000	6.375	2029
Installment Purchase Contracts	40,000	Variable	2028
Installment Purchase Contracts	40,000	Variable	2028
Installment Purchase Contracts	18,000	Variable	2029
Installment Purchase Contracts	18,000	Variable	2029
Notes Payable	1,463	6.81	2008
Notes Payable	3,250	6.27	2009

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

Roll-Forward of MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 47,777
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(11,363)
Fair Value of New Contracts When Entered During the Period (b)	374
Net Option Premiums Paid/(Received) (c)	-
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	9,814
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	-
Total MTM Risk Management Contract Net Assets	46,602
Net Cash Flow Hedge Contracts (f)	(9,770)
DETM Assignment (g)	(15,413)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$ 21,419

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(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 in 2005.
(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) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 99,111	$ 6,303	$ -	$ 105,414
Noncurrent Assets	106,219	811	-	107,030
Total MTM Derivative Contract Assets	205,330	7,114	-	212,444
Current Liabilities	(91,128)	(15,588)	(6,309)	(113,025)
Noncurrent Liabilities	(67,600)	(1,296)	(9,104)	(78,000)
Total MTM Derivative Contract Liabilities	(158,728)	(16,884)	(15,413)	(191,025)
Total MTM Derivative Contract Net Assets (Liabilities)	46,602	$ (9,770)	$ (15,413)	$ 21,419

(a) Does not include Cash Flow Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted – Exchange Traded Contracts	$ (6,874)	$ 2,647	$ 5,481	$ -	$ -	$ -	$ 1,254
Prices Provided by Other External Sources - OTC Broker Quotes (a)	16,284	11,207	10,584	4,544	-	-	42,619
Prices Based on Models and Other Valuation Methods (b)	(508)	(7,876)	(5,324)	3,759	6,716	5,962	2,729
Total	$ 8,902	$ 5,978	$ 10,741	$ 8,303	$ 6,716	$ 5,962	$ 46,602

(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) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $5.7 million of this mark-to-market value is in 2010.

(d) 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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ 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 Consolidated Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Foreign Currency	Total
Beginning Balance December 31, 2004	$ 1,599	$ (358)	$ 1,241
Changes in Fair Value (a)	(5,476)	-	(5,476)
Reclassifications from AOCI to Net Income (b)	(2,463)	3	(2,460)
Ending Balance March 31, 2005	$ (6,340)	$ (355)	$ (6,695)

(a) “Changes in Fair Value” shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $6,040 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$449	$994	$488	$294	$464	$1,513	$652	$223

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 $155 million and $146 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 456,231	$ 443,729
Sales to AEP Affiliates	151,839	146,488
TOTAL	608,070	590,217
OPERATING EXPENSES		
Fuel for Electric Generation	180,261	166,271
Purchased Electricity for Resale	18,762	12,183
Purchased Electricity from AEP Affiliates	25,618	19,303
Other Operation	73,783	91,096
Maintenance	45,755	34,051
Depreciation and Amortization	73,947	71,782
Taxes Other Than Income Taxes	47,142	47,190
Income Taxes	38,571	39,982
TOTAL	503,839	481,858
OPERATING INCOME	104,231	108,359
Nonoperating Income	54,972	16,751
Carrying Costs Income	22,037	179
Nonoperating Expenses	45,027	8,069
Nonoperating Income Tax Expense	10,567	5,087
Interest Charges	26,163	31,969
NET INCOME	99,483	80,164
Preferred Stock Dividend Requirements	183	183
EARNINGS APPLICABLE TO COMMON STOCK	$ 99,300	$ 79,981

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 321,201	$ 462,484	$ 729,147	$ (48,807)	$ 1,464,025
Common Stock Dividends			(57,057)		(57,057)
Preferred Stock Dividends			(183)		(183)
TOTAL					1,406,785
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,358				(2,522)	(2,522)
Minimum Pension Liability, Net of Tax of $2,123				(3,942)	(3,942)
NET INCOME			80,164		80,164
TOTAL COMPREHENSIVE INCOME					73,700
MARCH 31, 2004	$ 321,201	$ 462,484	$ 752,071	$ (55,271)	$ 1,480,485
DECEMBER 31, 2004	$ 321,201	$ 462,485	$ 764,416	$ (74,264)	$ 1,473,838
Common Stock Dividends			(7,500)		(7,500)
Preferred Stock Dividends			(183)		(183)
TOTAL					1,466,155
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,273				(7,936)	(7,936)
NET INCOME			99,483		99,483
TOTAL COMPREHENSIVE INCOME					91,547
MARCH 31, 2005	$ 321,201	$ 462,485	$ 856,216	$ (82,200)	$ 1,557,702

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 4,137,431	$ 4,127,284
Transmission	984,702	978,492
Distribution	1,213,373	1,202,550
General	242,690	248,749
Construction Work in Progress	329,393	240,957
Total	6,907,589	6,798,032
Accumulated Depreciation and Amortization	2,641,778	2,617,238
TOTAL – NET	4,265,811	4,180,794
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	44,743	44,774
Other	8,901	13,409
TOTAL	53,644	58,183
CURRENT ASSETS		
Cash and Cash Equivalents	1,083	9,300
Other Cash Deposits	9,986	37
Advances to Affiliates	41,407	125,971
Accounts Receivable:		
Customers	112,135	109,592
Affiliated Companies	147,532	144,175
Miscellaneous	27,144	7,626
Allowance for Uncollectible Accounts	(37)	(93)
Fuel	69,506	70,309
Materials and Supplies	56,855	55,569
Emissions Allowances	48,097	95,303
Risk Management Assets	105,414	79,541
Margin Deposits	11,926	7,056
Prepayments and Other	16,598	10,492
TOTAL	647,646	714,878
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	171,688	169,866
Transition Regulatory Assets	202,908	225,273
Unamortized Loss on Reacquired Debt	10,866	11,046
Other	65,433	22,189
Long-term Risk Management Assets	107,030	66,727
Deferred Property Taxes	54,556	70,214
Deferred Charges and Other Assets	63,973	74,095
TOTAL	676,454	639,410
TOTAL ASSETS	$ 5,643,555	$ 5,593,265

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
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	462,485	462,485
Retained Earnings	856,216	764,416
Accumulated Other Comprehensive Income (Loss)	(82,200)	(74,264)
Total Common Shareholder's Equity	1,557,702	1,473,838
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,641
Total Shareholders' Equity	1,574,343	1,490,479
Long-term Debt:		
Nonaffiliated	1,594,364	1,598,706
Affiliated	400,000	400,000
Total Long-term Debt	1,994,364	1,998,706
TOTAL	3,568,707	3,489,185
Minority Interest	13,475	14,083
CURRENT LIABILITIES		
Short-term Debt – Nonaffiliated	18,702	23,498
Long-term Debt Due Within One Year – Nonaffiliated	12,354	12,354
Cumulative Preferred Stock Subject to Mandatory Redemption	-	5,000
Accounts Payable:		
General	190,301	143,247
Affiliated Companies	60,079	116,615
Customer Deposits	30,991	22,620
Taxes Accrued	159,776	233,026
Interest Accrued	23,045	39,254
Risk Management Liabilities	113,025	70,311
Obligations Under Capital Leases	8,806	9,081
Other	71,539	74,977
TOTAL	688,618	749,983
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	945,105	943,465
Regulatory Liabilities:		
Asset Removal Costs	105,503	102,875
Deferred Investment Tax Credits	12,290	12,539
Long-term Risk Management Liabilities	78,000	46,261
Deferred Credits	43,280	24,377
Employee Benefits and Pension Obligations	106,201	126,825
Obligations Under Capital Leases	29,867	31,652
Asset Retirement Obligations	46,494	45,606
Other	6,015	6,414
TOTAL	1,372,755	1,340,014
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,643,555	$ 5,593,265

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 99,483	$ 80,164
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	73,947	71,782
Deferred Income Taxes	4,092	7,701
Deferred Investment Tax Credits	(249)	(761)
Deferred Property Taxes	15,658	14,745
Pension and Postemployment Benefit Reserves	(617)	4,160
Mark-to-Market of Risk Management Contracts	(2,477)	(5,729)
Pension Contributions	(20,007)	-
Carrying Costs Income	(22,037)	(179)
Change in Other Noncurrent Assets	(12,780)	(11,116)
Change in Other Noncurrent Liabilities	19,811	(2,682)
Changes in Components of Working Capital:		
Accounts Receivable, Net	(25,474)	(13,886)
Fuel, Materials and Supplies	(483)	2,743
Accounts Payable	(9,482)	(21,674)
Taxes Accrued	(73,250)	18,336
Customer Deposits	8,371	10,280
Interest Accrued	(16,209)	(16,934)
Other Current Assets	40,237	618
Other Current Liabilities	(3,713)	(12,437)
Net Cash Flows From Operating Activities	74,821	125,131
INVESTING ACTIVITIES		
Construction Expenditures	(134,848)	(49,868)
Change in Other Cash Deposits, Net	(9,949)	50,953
Proceeds from Sale of Assets	589	1,102
Net Cash Flows From (Used For) Investing Activities	(144,208)	2,187
FINANCING ACTIVITIES		
Change in Short-term Debt, Net	(4,796)	631
Issuance of Long-term Debt	216,798	-
Issuance of Long-term Debt– Affiliated	-	200,000
Retirement of Long-term Debt– Nonaffiliated	(222,713)	(192,963)
Retirement of Cumulative Preferred Stock	(5,000)	(2,250)
Changes in Advances to/from Affiliates, Net	84,564	(71,970)
Dividends Paid on Common Stock	(7,500)	(57,057)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Net Cash Flows From (Used For) Financing Activities	61,170	(123,792)
Net Increase (Decrease) in Cash and Cash Equivalents	(8,217)	3,526
Cash and Cash Equivalents at Beginning of Period	9,300	7,233
Cash and Cash Equivalents at End of Period	$ 1,083	$ 10,759

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $37,519,000 and $46,636,000 and for income taxes was $87,763,000 and $(8,644,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $555,000 and $0 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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.

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income
(in millions)

First Quarter of 2004 Net Income		$ (9)
Changes in Gross Margin:		
Retail Margins	(4)	
Off-system Sales	3	
Total Change in Gross Margin		(1)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	15	
Depreciation and Amortization	(1)	
Interest Charges	2	
Total Change in Operating Expenses and Other		16
Income Tax Expense		(6)
First Quarter of 2005 Net Income		$ -

Net Income increased $9 million in the first quarter of 2005. The key drivers of the increase were a $16 million decrease in operating expenses and other partially offset by a $6 million increase in income taxes and a $1 million decrease in gross margin. Fluctuations occurring in retail fuel revenues generally do not impact operating income, as they are offset in the retail portion of fuel and purchased power expense due to the functioning of the fuel adjustment clause in Oklahoma.

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

- Retail Margins decreased by $4 million in comparison to 2004 primarily due to a $1 million decrease in retail sales due to slightly lower volumes and a $2 million decrease in net fuel revenue/fuel expense.
- Margins from Off-system Sales for 2005 increased by $3 million in comparison to 2004 primarily due to higher sales volumes of approximately 9% as well as higher optimization activity.

Operating Expenses and Other decreased between years as follows:

- Other Operation and Maintenance expenses decreased $15 million. Transmission related expenses decreased $6 million primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data for the years 2001 through 2003 of approximately $5 million. Distribution expenses decreased $2 million resulting primarily from a 2004 labor settlement. Administrative and general expenses decreased approximately $6 million due to lower outside service and employee related expenses, while customer related expenses increased $1 million. Maintenance expenses decreased $2 million primarily due to higher 2004 cost of scheduled plant maintenance offset in part by increased maintenance of overhead lines.
- Interest Charges decreased $2 million primarily due to the retirement of higher rate First Mortgage Bonds replaced by lower rate Senior Unsecured Notes and the retirement of Trust Preferred Securities in 2004.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 184.9% and 46.2%, 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, state income taxes and federal income tax adjustments. The increase in the effective tax rate from the comparative period is primarily due to higher pre-tax income in 2005 and federal income tax adjustments.

Financial Condition

Credit Ratings

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

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

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2005.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Significant Factors

Oklahoma Regulatory Activity

PSO Rate Review

We are involved in a commission staff-initiated rate review before the OCC seeking to increase our base rates, while various other parties made recommendations to reduce our base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that we may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

PSO Fuel and Purchased Power

In 2002, we 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, we submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending we recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of our 2001 fuel and purchased power practices.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, we estimate that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of our fuel and purchased power for 2003. We are unable to predict if the OCC will order a prudence review of our fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	14,771
(Gain) Loss from Contracts Realized/Settled During the Period (a)		115
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		-
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)		(10,588)
Total MTM Risk Management Contract Net Assets		4,298
Net Cash Flow Hedge Contracts (f)		(913)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	3,385

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(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 in 2005.

(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) "Changes 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" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 7,540	$ 908	$ 8,448
Noncurrent Assets	6,510	70	6,580
Total MTM Derivative Contract Assets	14,050	978	15,028
Current Liabilities	(6,692)	(1,716)	(8,408)
Noncurrent Liabilities	(3,060)	(175)	(3,235)
Total MTM Derivative Contract Liabilities	(9,752)	(1,891)	(11,643)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,298	$ (913)	$ 3,385

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

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

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

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

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

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (927)	$ 357	$ 739	$ -	$ -	$ -	$ 169
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,804	1,532	1,127	483	-	-	4,946
Prices Based on Models and Other Valuation Methods (b)	21	(1,302)	(1,086)	263	580	707	(817)
Total	$ 898	$ 587	$ 780	$ 746	$ 580	$ 707	$ 4,298

(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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,000	$ (600)	$ 400
Changes in Fair Value (a)	(1,570)	945	(625)
Reclassifications from AOCI to Net Income (b)	(368)	-	(368)
Ending Balance March 31, 2005	$ (938)	$ 345	$ (593)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 an $810 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$61	$134	$66	$40	$238	$778	$335	$115

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 $35 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 250,368	$ 204,043
Sales to AEP Affiliates	2,632	3,142
TOTAL	253,000	207,185
OPERATING EXPENSES		
Fuel for Electric Generation	134,171	89,085
Purchased Electricity for Resale	14,793	9,168
Purchased Electricity from AEP Affiliates	22,845	26,899
Other Operation	30,185	43,395
Maintenance	11,359	13,122
Depreciation and Amortization	22,619	22,176
Taxes Other Than Income Taxes	9,677	9,817
Income Taxes (Credits)	(852)	(7,333)
TOTAL	244,797	206,329
OPERATING INCOME	8,203	856
Nonoperating Income	478	244
Nonoperating Expenses	551	542
Nonoperating Income Tax Credit	250	392
Interest Charges	7,875	9,953
NET INCOME (LOSS)	505	(9,003)
Preferred Stock Dividend Requirements	53	53
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 452	$ (9,056)

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 COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 157,230	$ 230,016	$ 139,604	$ (43,842)	$ 483,008
Common Stock Dividends			(8,750)		(8,750)
Preferred Stock Dividends			(53)		(53)
TOTAL					474,205
COMPREHENSIVE LOSS					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $239				(444)	(444)
NET LOSS			(9,003)		(9,003)
TOTAL COMPREHENSIVE LOSS					(9,447)
MARCH 31, 2004	$ 157,230	$ 230,016	$ 121,798	$ (44,286)	$ 464,758
DECEMBER 31, 2004	$ 157,230	$ 230,016	$ 141,935	$ 75	$ 529,256
Common Stock Dividends			(8,500)		(8,500)
Preferred Stock Dividends			(53)		(53)
TOTAL					520,703
COMPREHENSIVE LOSS					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $534				(993)	(993)
NET INCOME			505		505
TOTAL COMPREHENSIVE LOSS					(488)
MARCH 31, 2005	$ 157,230	$ 230,016	$ 133,887	$ (918)	$ 520,215

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,068,205	$ 1,072,022
Transmission	467,953	468,735
Distribution	1,100,348	1,089,187
General	201,397	200,044
Construction Work in Progress	47,129	41,028
Total	2,885,032	2,871,016
Accumulated Depreciation and Amortization	1,126,729	1,117,113
TOTAL - NET	1,758,303	1,753,903
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,636	4,401
Other Investments	-	81
TOTAL	4,636	4,482
CURRENT ASSETS		
Cash and Cash Equivalents	642	91
Other Cash Deposits	156	188
Accounts Receivable:		
Customers	31,319	34,002
Affiliated Companies	31,288	46,399
Miscellaneous	8,747	6,984
Allowance for Uncollectible Accounts	-	(76)
Fuel Inventory	14,674	14,268
Materials and Supplies	37,950	35,485
Risk Management Assets	8,448	21,388
Regulatory Asset for Under-Recovered Fuel Costs	-	366
Margin Deposits	1,388	2,881
Prepayments and Other	2,532	1,378
TOTAL	137,144	163,354
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	14,143	14,705
Other	16,401	17,246
Long-term Risk Management Assets	6,580	14,477
Prepaid Pension Obligations	82,466	82,419
Deferred Charges and Other Assets	39,958	18,232
TOTAL	159,548	147,079
TOTAL ASSETS	$ 2,059,631	$ 2,068,818

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $15 par value per share:		
Authorized - 11,000,000 shares		
Issued - 10,482,000 shares		
Outstanding - 9,013,000 shares	$ 157,230	$ 157,230
Paid-in Capital	230,016	230,016
Retained Earnings	133,887	141,935
Accumulated Other Comprehensive Income (Loss)	(918)	75
Total Common Shareholder's Equity	520,215	529,256
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Total Shareholders' Equity	525,477	534,518
Long-term Debt:		
Nonaffiliated	446,121	446,092
Affiliated	50,000	50,000
Total Long-term Debt	496,121	496,092
TOTAL	1,021,598	1,030,610
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Nonaffiliated	50,000	50,000
Advances from Affiliates	39,588	55,002
Accounts Payable:		
General	66,278	71,442
Affiliated Companies	53,755	58,632
Customer Deposits	33,867	33,757
Taxes Accrued	33,817	18,835
Interest Accrued	2,725	4,023
Risk Management Liabilities	8,408	13,705
Regulatory Liability for Over-Recovered Fuel Costs	40,529	-
Obligations Under Capital Leases	603	537
Other	18,449	30,477
TOTAL	348,019	336,410
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	386,293	384,090
Long-term Risk Management Liabilities	3,235	7,455
Regulatory Liabilities:		
Asset Removal Costs	225,316	220,298
Deferred Investment Tax Credits	28,172	28,620
SFAS 109 Regulatory Liability, Net	21,351	21,963
Unrealized Gain on Forward Commitments	7,339	19,676
Obligations Under Capital Leases	1,086	747
Deferred Credits and Other	17,222	18,949
TOTAL	690,014	701,798
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,059,631	$ 2,068,818

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income (Loss)	$ 505	$ (9,003)
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	22,619	22,176
Deferred Property Taxes	(24,368)	(25,943)
Deferred Income Taxes	2,126	(489)
Deferred Investment Tax Credits	(448)	(448)
Mark-to-Market of Risk Management Contracts	10,473	10,029
Fuel Recovery	40,895	4,398
Change in Other Noncurrent Assets	(4,964)	(1,664)
Change in Other Noncurrent Liabilities	(9,279)	(7,768)
Changes in Components of Working Capital:		
Accounts Receivable, Net	15,955	4,054
Fuel, Materials and Supplies	(2,871)	635
Accounts Payable	(10,041)	(7,740)
Taxes Accrued	14,982	17,424
Customer Deposits	110	2,357
Interest Accrued	(1,298)	32
Other Current Assets	2,285	(576)
Other Current Liabilities	(11,964)	(4,562)
Net Cash Flows From Operating Activities	44,717	2,912
INVESTING ACTIVITIES		
Construction Expenditures	(20,231)	(14,471)
Change in Other Cash Deposits, Net	32	3,688
Proceeds from Sale of Assets	-	244
Net Cash Flows Used For Investing Activities	(20,199)	(10,539)
FINANCING ACTIVITIES		
Changes in Advances to/from Affiliates, Net	(15,414)	14,778
Dividends Paid on Common Stock	(8,500)	(8,750)
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Net Cash Flows From (Used For) Financing Activities	(23,967)	5,975
Net Increase (Decrease) in Cash and Cash Equivalents	551	(1,652)
Cash and Cash Equivalents at Beginning of Period	91	3,738
Cash and Cash Equivalents at End of Period	$ 642	$ 2,086

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $7,806,000 and $8,951,000 and for income taxes was $(1,366,000) and $(2,695,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $551,000 and $141,000 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005 Net Income (in millions)

First Quarter of 2004 Net Income		$ 5
Changes in Gross Margin:		
Retail Margins*	3	
Off-system Sales	(1)	
Other Revenues	1	
Total Change in Gross Margin		3
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	5	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	1	
Interest Charges	3	
Total Change in Operating Expenses and Other:		8
Income Tax Expense		(4)
First Quarter of 2005 Net Income		$ 12

* Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $7 million to $12 million in the first quarter of 2005. The key drivers of the increase were a $3 million increase in gross margin and an $8 million net decrease in operating expenses and other partially offset by a $4 million increase in income taxes.

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

- Retail Margins increased $3 million in comparison to 2004 primarily due to a $1 million increase in retail sales due to slightly higher volumes and a $2 million increase in net fuel revenue/fuel expense.
- Margins from Off-system Sales decreased $1 million in comparison to 2004 primarily due to lower optimization activity.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $5 million. Transmission related expenses decreased $6 million primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data for the years 2001 through 2003, offset in part by $1 million of higher production plant related expenses.
- Taxes Other Than Income Taxes decreased $1 million primarily due to property related taxes and state franchise taxes.
- Interest Charges decreased $3 million primarily due to refinancing higher interest rate debt with lower interest rate debt.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 26.5% and (4.7%), 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, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to higher pretax income in 2005 and federal income tax adjustments.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the three months ended March 31, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ 2,308	$ 5,676
Cash flows from (used for):		
Operating activities	53,866	16,892
Investing activities	(33,260)	(72,298)
Financing activities	(15,941)	56,959
Net increase in cash and cash equivalents	4,665	1,553
Cash and cash equivalents at end of period	$ 6,973	$ 7,229

Operating Activities

Our net cash flows from operating activities were $54 million in 2005. We produced income of $12 million during the period and noncash expense items of $32 million for Depreciation and Amortization and $(29) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net, Fuel, Materials and Supplies, Accounts Payable and Taxes Accrued. Accounts Receivable, Net decreased $13 million related to decreased affiliated energy transactions. The $2 million decrease in Fuel, Materials and Supplies is primarily due to lower purchases of fuel. Accounts Payable decreased $6 million due primarily to lower vendor related payables and lower affiliated energy transactions. Taxes Accrued increased $16 million primarily due to the annual tax accruals related to 2005 property taxes offset in part by a reduction of income tax related accruals.

Our net cash flows from operating activities were $17 million in 2004. We produced income of $5 million during the period and noncash expense items of $31 million for Depreciation and Amortization and $(29) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net, Fuel, Materials and Supplies, Accounts Payable and Taxes Accrued. Accounts Receivables, Net increased $13 million related to affiliated energy transactions. The $6 million decrease in Fuel, Materials and Supplies is primarily due to lower purchases of fuel. Accounts Payable decreased $14 million primarily due to lower vendor related payables and lower affiliated energy transactions. Taxes Accrued increased $40 million primarily due to the annual tax accruals related to 2004 property taxes and by an increase of income tax related accruals.

Investing Activities

Cash flows used for investing activities during 2005 and 2004 were $33 million and $72 million, respectively. They were comprised of Construction Expenditures related to projects for improved transmission and distribution service reliability and in 2004, a Change in Other Cash Deposits, Net related to funds held in trust for the retirement of Installment Purchase Contracts. For the remainder of 2005, we expect our Construction Expenditures to be approximately $170 million.

Financing Activities

Cash flows from financing activities were $16 million during 2005. During the first quarter, we retired $2 million of Notes Payable. Common stock dividends were $13 million.

Cash flows from financing activities were $57 million during 2004. During the first quarter, we increased our Utility Money Pool borrowing by $103 million, retired $83 million of First Mortgage Bonds, issued $52 million of Installment Purchase Contracts and paid $15 million in common stock dividends.

Financing Activity

There were no long-term debt issuances during the first three months of 2005. Retirements are shown below:

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Note Payable	$1,707	4.47	2011
Note Payable	750	Variable	2008

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity.

Significant Factors

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	17,527
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(2,871)
Fair Value of New Contracts When Entered During the Period (b)		21
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(1,448)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		(8,121)
Total MTM Risk Management Contract Net Assets		5,108
Net Cash Flow Hedge Contracts (f)		(4,095)
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	1,013

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(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 in 2005.
(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) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 9,003	$ 449	$ 9,452
Noncurrent Assets	7,756	82	7,838
Total MTM Derivative Contract Assets	16,759	531	17,290
Current Liabilities	(7,996)	(4,142)	(12,138)
Noncurrent Liabilities	(3,655)	(484)	(4,139)
Total MTM Derivative Contract Liabilities	(11,651)	(4,626)	(16,277)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5,108	$ (4,095)	$ 1,013

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of March 31, 2005

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (1,102)	$ 424	$ 878	$ -	$ -	$ -	$ 200
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,145	1,821	1,339	574	-	-	5,879
Prices Based on Models and Other Valuation Methods (b)	24	(1,547)	(1,291)	313	690	840	(971)
Total	$ 1,067	$ 698	$ 926	$ 887	$ 690	$ 840	$ 5,108

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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

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 and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table indicates 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
Three Months Ended March 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,188	$ (2,008)	$ (820)
Changes in Fair Value (a)	(1,867)	774	(1,093)
Reclassifications from AOCI to Net Income (b)	(436)	-	(436)
Ending Balance March 31, 2005	$ (1,115)	$ (1,234)	$ (2,349)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. 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 $1,123 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$72	$159	$78	$47	$283	$923	$398	$136

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 $32 million and $31 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 229,874	$ 213,949
Sales to AEP Affiliates	17,122	22,211
TOTAL	246,996	236,160
OPERATING EXPENSES		
Fuel for Electric Generation	90,110	88,823
Purchased Electricity for Resale	13,380	5,934
Purchased Electricity from AEP Affiliates	5,864	7,307
Other Operation	44,449	50,268
Maintenance	15,715	15,648
Depreciation and Amortization	32,393	31,285
Taxes Other Than Income Taxes	15,663	16,567
Income Taxes	4,596	131
TOTAL	222,170	215,963
OPERATING INCOME	24,826	20,197
Nonoperating Income	1,319	1,403
Nonoperating Expenses	474	611
Nonoperating Income Tax Credit	200	356
Interest Charges	12,780	15,443
Minority Interest	(886)	(881)
NET INCOME	12,205	5,021
Preferred Stock Dividend Requirements	57	57
EARNINGS APPLICABLE TO COMMON STOCK	$ 12,148	$ 4,964

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 COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 135,660	$ 245,003	$ 359,907	$ (43,910)	$ 696,660
Common Stock Dividends			(15,000)		(15,000)
Preferred Stock Dividends			(57)		(57)
TOTAL					681,603
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $281				(522)	(522)
Minimum Pension Liability, Net of Tax of $12,420				23,066	23,066
NET INCOME			5,021		5,021
TOTAL COMPREHENSIVE INCOME					27,565
MARCH 31, 2004	$ 135,660	$ 245,003	$ 349,871	$ (21,366)	$ 709,168
DECEMBER 31, 2004	$ 135,660	$ 245,003	$ 389,135	$ (1,180)	$ 768,618
Common Stock Dividends			(12,500)		(12,500)
Preferred Stock Dividends			(57)		(57)
TOTAL					756,061
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $824				(1,529)	(1,529)
NET INCOME			12,205		12,205
TOTAL COMPREHENSIVE INCOME					10,676
MARCH 31, 2005	$ 135,660	$ 245,003	$ 388,783	$ (2,709)	$ 766,737

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,668,689	$ 1,663,161
Transmission	634,206	632,964
Distribution	1,121,224	1,114,480
General	428,751	427,910
Construction Work in Progress	59,465	48,852
Total	3,912,335	3,887,367
Accumulated Depreciation and Amortization	1,734,533	1,709,758
TOTAL - NET	2,177,802	2,177,609
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,049	4,049
Other Investments	4,628	4,628
TOTAL	8,677	8,677
CURRENT ASSETS		
Cash and Cash Equivalents	6,973	2,308
Other Cash Deposits	6,504	6,292
Advances to Affiliates	40,033	39,106
Accounts Receivable:		
Customers	40,117	39,042
Affiliated Companies	14,733	28,817
Miscellaneous	5,834	5,856
Allowance for Uncollectible Accounts	(5)	(45)
Fuel Inventory	42,531	45,793
Materials and Supplies	36,886	36,051
Risk Management Assets	9,452	25,379
Regulatory Asset for Under-Recovered Fuel Costs	-	4,687
Margin Deposits	1,650	3,419
Prepayments and Other	17,639	18,331
TOTAL	222,347	255,036
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	20,874	18,000
Unamortized Loss on Reacquired Debt	20,067	20,765
Other	14,100	16,350
Long-term Risk Management Assets	7,838	17,179
Prepaid Pension Obligations	80,941	81,132
Deferred Charges	74,217	51,561
TOTAL	218,037	204,987
TOTAL ASSETS	$ 2,626,863	$ 2,646,309

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $18 par value per share:		
Authorized - 7,600,000 shares		
Outstanding - 7,536,640 shares	$ 135,660	$ 135,660
Paid-in Capital	245,003	245,003
Retained Earnings	388,783	389,135
Accumulated Other Comprehensive Income (Loss)	(2,709)	(1,180)
Total Common Shareholder's Equity	766,737	768,618
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders' Equity	771,437	773,318
Long-term Debt:		
Nonaffiliated	535,525	545,395
Affiliated	50,000	50,000
Total Long-term Debt	585,525	595,395
TOTAL	1,356,962	1,368,713
Minority Interest	1,921	1,125
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	217,474	209,974
Accounts Payable:		
General	36,154	40,001
Affiliated Companies	30,719	33,285
Customer Deposits	29,684	30,550
Taxes Accrued	61,590	45,474
Interest Accrued	11,523	12,509
Risk Management Liabilities	12,138	18,607
Obligations Under Capital Leases	4,052	3,692
Regulatory Liability for Over-Recovered Fuel Costs	13,655	9,891
Other	32,083	33,417
TOTAL	449,072	437,400
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	397,563	399,756
Long-term Risk Management Liabilities	4,139	9,128
Reclamation Reserve	5,761	7,624
Regulatory Liabilities:		
Asset Removal Costs	250,637	249,892
Deferred Investment Tax Credits	34,466	35,539
Excess Earnings	3,167	3,167
Other	11,104	21,320
Asset Retirement Obligations	27,518	27,361
Obligations Under Capital Leases	30,525	30,854
Deferred Credits and Other	54,028	54,430
TOTAL	818,908	839,071
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,626,863	$ 2,646,309

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 Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 12,205	$ 5,021
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	32,393	31,285
Deferred Property Taxes	(28,570)	(29,063)
Deferred Income Taxes	(4,312)	(5,182)
Deferred Investment Tax Credits	(1,073)	(1,081)
Mark-to-Market of Risk Management Contracts	12,419	11,837
Over/Under Fuel Recovery	8,451	9,649
Change in Other Noncurrent Assets	4,760	1,175
Change in Other Noncurrent Liabilities	(10,413)	(3,620)
Changes in Components of Working Capital:		
Accounts Receivable, Net	12,991	(12,895)
Fuel, Materials and Supplies	2,427	6,226
Accounts Payable	(6,413)	(13,590)
Taxes Accrued	16,116	39,682
Customer Deposits	(866)	2,132
Interest Accrued	(986)	(2,598)
Other Current Assets	4,849	901
Other Current Liabilities	(112)	(22,987)
Net Cash Flows From Operating Activities	53,866	16,892
INVESTING ACTIVITIES		
Construction Expenditures	(33,156)	(19,376)
Change in Other Cash Deposits, Net	(212)	(52,922)
Proceeds from Sale of Assets	108	-
Net Cash Flows Used For Investing Activities	(33,260)	(72,298)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	-	52,179
Retirement of Long-term Debt	(2,457)	(82,907)
Changes in Advances to/from Affiliates, Net	(927)	102,744
Dividends Paid on Common Stock	(12,500)	(15,000)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows From (Used For) Financing Activities	(15,941)	56,959
Net Increase in Cash and Cash Equivalents	4,665	1,553
Cash and Cash Equivalents at Beginning of Period	2,308	5,676
Cash and Cash Equivalents at End of Period	$ 6,973	$ 7,229

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $12,304,000 and $15,964,000 and for income taxes was $22,257,000 and $(2,228,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $775,000 and $887,000 in 2005 and 2004, respectively.

See Notes to Respective Financial Statements 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	CSPCo, OPCo, 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 2004 Annual Report as incorporated in and filed with our 2004 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 capitalization section. The components of Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries are shown in the following table:

Components	March 31, 2005	December 31, 2004
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (17,034)	$ (9,324)
CSPCo	(4,381)	1,393
I&M	(10,389)	(4,076)
KPCo	(1,814)	813
OPCo	(6,695)	1,241
PSO	(593)	400
SWEPCo	(2,349)	(820)
TCC	(3,679)	657
TNC	(489)	285
Minimum Pension Liability:		
APCo	$ (72,348)	$ (72,348)
CSPCo	(62,209)	(62,209)
I&M	(41,175)	(41,175)
KPCo	(9,588)	(9,588)
OPCo	(75,505)	(75,505)
PSO	(325)	(325)
SWEPCo	(360)	(360)
TCC	(4,816)	(4,816)
TNC	(413)	(413)

Accounting for Asset Retirement Obligations

All of AEP's Registrant Subsidiaries 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:

	Balance at January 1, 2005	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at March 31, 2005
			(in millions)			
AEGCo (a)	$ 1.2	$ -	$ -	$ -	$ -	$ 1.2
APCo (a)	24.6	0.5	-	-	-	25.1
CSPCo (a)	11.6	0.2	-	-	-	11.8
I&M (b)	711.8	11.6	-	-	-	723.4
OPCo (a)	45.6	0.9	-	-	-	46.5
SWEPCo (c)	27.4	0.2	-	(0.1)	-	27.5
TCC (d)	248.9	4.5	-	-	-	253.4

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.2 million at March 31, 2005) and nuclear decommissioning costs for the Cook Plant ($722.2 million at March 31, 2005).
(c) Consists of asset retirement obligations related to Sabine Mining Company and Dolet Hills Lignite Company, LLC.
(d) 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.

Accretion expense is included in Other Operation expense in the respective income statements of the individual registrant subsidiaries.

As of March 31, 2005 and December 31 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $962 million ($819 million for I&M and $143 million for TCC) and $934 million ($791 million for I&M and $143 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).

Prior Period Adjustment

As disclosed in the 2004 Annual Report, in the second quarter of 2004 the Registrant Subsidiaries implemented FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 (FSP FAS 106-2), retroactive to January 1, 2004. The effect of implementing FSP FAS 106-2 on 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	414	45,119
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

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2005 that we have determined relate to our operations.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25. The statement is effective as of the first annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement.

We will implement SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. The Registrant Subsidiaries do not expect implementation of SFAS 123R to materially affect their results of operations, cash flows or financial condition.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies.

FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143. FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

The Registrant Subsidiaries will implement FIN 47 during the fourth quarter of 2005. Implementation will require an adjustment for the cumulative effect for the nonregulated operations of initially applying FIN 47 to be recorded as a change in accounting principle, disclosure of pro forma liabilities and asset retirement obligations, and other additional disclosures. The Registrant Subsidiaries have not completed their evaluation of any potential impact to their results of operations, cash flows or financial condition.

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 business combinations, operating segments, liabilities and equity, revenue recognition, pension plans, fair value measurements, accounting changes and related tax impacts. We also expect to see more FASB projects as a result of their 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 2004 Annual Report, rate and regulatory proceedings at the FERC and at several state commissions are ongoing. The Rate Matters note within our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending. The following sections discuss current activities and update the 2004 Annual Report.

Louisiana Fuel Audit – Affecting SWEPCo

The Louisiana Public Service Commission (LPSC) is performing an audit of SWEPCo's historical fuel costs and addressing customer complaints regarding potential overcharge of fuel costs. In testimony filed in this matter, the LPSC Staff recommended refunds of approximately $5 million. In subsequent surrebuttal testimony filed by the LPSC Staff, they recognized that SWEPCo's costs were reasonable but that certain costs would be more appropriately recovered through base rates. While initial indications from the LPSC Staff surrebuttal testimony would not indicate a material disallowance, management cannot predict the ultimate outcome in this proceeding. If the LPSC or the Court does not agree with LPSC Staff recommendations, it could have an adverse effect on SWEPCo's future 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 submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation 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.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, PSO estimates that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power for 2003. Management is unable to predict if the OCC will order a prudence review of PSO's fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on PSO's revenues, results of operations, cash flows and financial condition.

Michigan Fuel Recovery Plan – Affecting I&M

In September 2004, I&M filed its 2005 Power Supply Cost Recovery (PSCR) Plan, with the requested PSCR factors implemented pursuant to the statute effective with January 2005 billings, replacing the 2004 factors. On March 29, 2005, the Michigan Public Service Commission (MPSC) issued an order approving a settlement agreement authorizing the proposed 2005 PSCR Plan factors.

On March 31, 2005, I&M filed its 2004 PSCR Reconciliation seeking recovery of approximately $2 million of unrecovered PSCR fuel costs and interest proposed to be recovered through the application of customer bill surcharges during October 2005 through December 2005.

On April 28, 2005, the MPSC issued an Opinion and Order approving I&M's proposed 2004 PSCR factors as billed and finding in favor of I&M on all issues, including the proposed treatment of net SO_2 and NO_x credits.

TCC Rate Case – Affecting TCC

TCC has an on-going transmission and distribution (T&D) rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements, which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJs recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If TCC were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing TCC's rates could have an adverse effect on TCC's future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal - Affecting TCC

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale of the AEP REPs is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on TCC's future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal - Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. In June 2003, the Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $3 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on TCC's and TNC's future results of operations and cash flows.

PSO Rate Review – Affecting PSO

PSO is involved in a commission staff-initiated rate review before the OCC seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

Indiana Settlement Agreement – Affecting I&M

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005, and filed the agreement with the IURC on March 14, 2005. The IURC may rule on the agreement during the second quarter of 2005.

The filed settlement freezes fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per for KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel rate freeze period, I&M will receive credit for 30% of the savings produced and customers will be credited with 70% of these savings over the first two fuel filings after the fuel rate freeze period ends in June 2007.

Pending approval of the IURC, this settlement agreement also freezes base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this freeze period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

If the settlement is approved by the IURC, fuel costs previously expensed since January 2005 exceeding the previously authorized level of 9.2 mills up to 9.88 mills (approximately $4 million through March 31, 2005) would be deferred for future recovery. If future fuel cost per KWH exceeds the caps, or if the base rate freeze precludes I&M from seeking timely rate increases to recover increases in I&M's cost of service, I&M's future results of operations and cash flows would be adversely affected.

RTO Formation/Integration – Affecting APCo, CSPCo, I&M, KPCo, and OPCo

Prior to joining PJM, the AEP East companies deferred costs incurred under FERC orders to originally form a new RTO, (the Alliance) and subsequently to join an existing RTO (PJM). In 2004, we requested permission to amortize, beginning January 1, 2005, the $18 million of deferred non-PJM billed formation/integration costs over 15 years and the $17 million of deferred PJM-billed integration costs, but we did not propose an amortization period for the PJM-billed costs in the application. The FERC approved our application.

In January 2005, the AEP East companies began amortizing their deferred non-PJM billed costs over 15 years and the deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was $1 million in the first quarter of 2005. As of March 31, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

Company	(in millions)
APCo	$ 9.7
CSPCo	4.0
I&M	7.4
KPCo	2.2
OPCo	11.0

On March 8, 2005, we jointly filed with other utilities a request with the FERC to recover deferred PJM-billed integration costs of $17 million from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. On March 31, 2005, we also filed a request for a revised network integration transmission service revenue requirement for the AEP zone of PJM. Included in the costs reflected in that revenue requirement was the budgeted 2005 amortization of our deferred non-PJM billed Alliance RTO formation and PJM integration costs. The AEP East companies will be responsible for paying most of the amounts allocated by the FERC to the AEP East zone since the costs are attributable to their internal load.

Although several parties have filed protests of the joint filing to recover the deferred PJM-billed integration costs, we believe that it is probable that the FERC will ultimately approve recovery of the PJM-billed integration costs through the PJM OATT and that the FERC will grant a long enough amortization period to allow us to recover the deferred non-PJM billed Alliance RTO formation and PJM integration costs in the AEP East retail jurisdictions. If the FERC issues an adverse ruling, the AEP East companies' future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. SECA billings by PJM crediting AEP for its SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005. Based upon the SECA transition rate methodology approved by the FERC, the AEP East companies accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005.

Company	SECA Revenue for Three Months Ended March 31, 2005 (in millions)	SECA Receivable at March 31, 2005 (in millions)
APCo	$ 8.6	$ 12.1
CSPCo	4.4	6.4
I&M	4.9	7.1
KPCo	2.0	2.8
OPCo	6.1	8.9

In a March 2005 FERC filing, we proposed an increase in the rate for network integration transmission service, as well as rates for other ancillary services. The primary customers of these services are the municipal and cooperative wholesale entities that have load delivery points in the AEP zone of PJM. As proposed, the rates will automatically increase to reflect the loss of SECA transition rates on April 1, 2006.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding – Affecting AEP East companies

In a July 2002 order conditionally accepting AEP East companies' choice to join PJM, the FERC directed ComEd, MISO, PJM and us to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from ComEd and us joining PJM instead of MISO.

In July 2004, AEP East companies and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for May 2005.

The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 million to $70 million over the term of the agreement for AEP East companies and ComEd. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP East companies and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP East companies and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP East companies and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120,000. Settlement negotiations are in progress with the remaining Michigan companies.

At this time, management is unable to predict the outcome of this proceeding. AEP East companies will support vigorously its positions before the FERC. If the FERC ultimately approves a significant hold-harmless payment to the Michigan utilities, it would adversely impact results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

As discussed in the 2004 Annual Report, certain AEP subsidiaries are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in the 2004 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

On January 26, 2005, the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding their approval of the rate stabilization plans. On March 23, 2005, the PUCO denied all applications for rehearing. In April 2005, an intervenor filed an appeal to the Ohio Supreme Court. Management cannot predict the ultimate impact appeal proceedings will have on the Ohio companies' future results of operations and cash flows.

TEXAS RESTRUCTURING – Affecting TCC and TNC

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items in TCC's future true-up filing. TCC has asked permission from the PUCT to file its True-up Proceeding after the sales of its interest in STP have been concluded, with only the ownership interest in Oklaunion remaining to be settled. If the request is approved, it is anticipated that TCC's True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of its net regulatory asset of $1.6 billion for its net stranded cost and other true-up items, which it believes the Texas Restructuring Legislation allows.

The Components of TCC's Net True-up Regulatory Asset as of March 31, 2005 and December 31, 2004 are:

	TCC	
	March 31, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1,141	1,136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1,346	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

The Components of TNC's Net True-up Regulatory Liability as of March 31, 2005 and December 31, 2004 are:

	TNC	
	March 31, 2005	**December 31, 2004**
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component which is not recoverable in fuel rates. In the first quarter of 2005, TCC recorded a provision for fuel revenue refund of $3 million, inclusive of interest, for this decision and continued to accrue interest on the deferred over-recovered fuel balance. This provision for refund results in a deferred over-recovery balance of $215 million as of March 31, 2005.

TCC Carrying Costs on Net True-up Regulatory Assets

TCC continues to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on TCC's net stranded cost and other true-up items which was applied retroactively to January 1, 2004. In the first quarter of 2005, TCC accrued carrying costs of $21 million which was more than offset by an adjustment based on this order of $27 million. The net reduction of $6 million in carrying costs is included in Nonoperating Income in the first quarter of 2005 on TCC's accompanying Statements of Income.

As of March 31, 2005, TCC has computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying costs of $154 million will be recognized in income as collected.

TCC Unrefunded Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first quarter of 2005, TCC refunded an additional $4 million reducing its unrefunded excess earnings to $6 million.

TCC True-up Proceeding

When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated T&D rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

The nonaffiliated utility's March order also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the competition transition charges (CTC). TCC estimates its present value ADFIT benefit to be $212 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's entire net true-up regulatory asset. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset over recovery periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in TCC's future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on TCC's future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In January 2005, intervenors made various recommendations including an increase in excess earnings of $5 million and a T&D rate reduction of $3 million annually. The intervenors also recommended that TNC's fuel over-recovery should be increased by $2 million. TNC is awaiting a PUCT decision and order and has recorded no disallowances based on intervenor contentions.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001. In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. TNC will pursue vigorously its appeals, but cannot predict their outcome.

5. <u>COMMITMENTS AND CONTINGENCIES</u>

As discussed in the Commitments and Contingencies note within the 2004 Annual Report, certain Registrant Subsidiaries continue to be involved in various legal matters. The 2004 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 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) carbon dioxide public nuisance claims, (2) nuclear matters, (3) construction commitments, (4) potential uninsured losses and (5) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in the 2004 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 have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated 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 occurred 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.

In June 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 filed a motion to amend its complaint and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, the Federal EPA and eight Northeastern States each filed an additional complaint containing the same allegations against the Amos and Conesville plants that the judge disallowed in the pending case. These complaints have been assigned to the same judge in the Southern District Court. AEP filed an answer to the complaint in January 2005, denying the allegations and stating its defenses.

In August 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, a nonaffiliated 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 nonroutine 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 settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at its plant.

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.

In August 2003, the District Court for the Middle District of South Carolina issued a decision in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court 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. The District Court denied the Federal EPA’s motion. In April 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated 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. The case is fully briefed and oral argument was heard in February 2005.

In June 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.

In June 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. Briefing continues in this case and oral argument was held in January 2005.

In December 2000, Cinergy Corp., a nonaffiliated 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.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. CSPCo owns a 26% share of the J.M. Stuart Station. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against TVA, the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. Management believes the allegations in the complaint are without merit, and intends to defend vigorously this action. 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.

Management is unable to estimate the loss or range of loss related to any contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

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 CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, 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. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May.

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 value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

OPERATIONAL

Power Generation Facility – Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 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. However, OPCo has entered an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted OPCo partial summary judgment on this issue, holding that the absences of operating protocols does not prevent enforcement of the PPA.

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 these electric power products 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 SUEZ-TRACTEBEL S.A. under the guaranty, damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005.

Merger Litigation–Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

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 HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Enron Bankruptcy - Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. The AEP subsidiaries have 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 nonbinding 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 nonbinding 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. Although management is unable to predict the outcome of these lawsuits it is possible that their resolution could have an adverse impact on our results of operations, cash flows or 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 nonaffiliated 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, 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. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Coal Transportation Dispute – Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs for coal received between July 2000 and the present time. The joint plant has remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in December 2004 and the first quarter of 2005. The provisions were deferred as a regulatory asset under PSO's fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letter of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At March 31, 2005, the maximum future payments of the LOCs include $44 million, $1 million, $51 million, $4 million and $43 million for CSPCo, I&M, OPCo, SWEPCo and TCC, respectively, with maturities ranging from November 2005 to April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $51 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At March 31, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

SWEPCo consolidates Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

Indemnifications and Other Guarantees

Contracts

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 2004 and the first quarter of 2005, 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 in July 2004. There are no material liabilities recorded for any indemnifications.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At March 31, 2005, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 5
CSPCo	2
I&M	3
KPCo	1
OPCo	5
PSO	4
SWEPCo	4
TCC	6
TNC	3

7. DISPOSITIONS AND ASSETS HELD FOR SALE

DISPOSITIONS ANTICIPATED BEING COMPLETED DURING 2005

Texas Plants – Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, TCC received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of its nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

Texas Plants – South Texas Project

In February 2004, TCC signed an agreement to sell its 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. In September 2004, TCC entered into sales agreements with two of its nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. TCC expects the sale to close in the second quarter of 2005. TCC's assets and liabilities related to STP have been classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in TCC's Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

The assets and liabilities of the TCC plants held for sale at March 31, 2005 and December 31, 2004 are as follows:

	Texas Plants	
	March 31, 2005	**December 31, 2004**
Assets:	**(in millions)**	
Other Current Assets	$ 25	$ 24
Property, Plant and Equipment, Net	416	413
Regulatory Assets	52	48
Nuclear Decommissioning Trust Fund	143	143
Total Assets Held for Sale – Texas Generation Plants	$ 636	$ 628
Liabilities:		
Regulatory Liabilities	$ 1	$ 1
Asset Retirement Obligations	254	249
Total Liabilities Held for Sale – Texas Generation Plants	$ 255	$ 250

8. <u>BENEFIT PLANS</u>

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, SWEPCo, 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 for the plans for the three months ended March 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Service Cost	$ 23	$ 22	$ 11	$ 10
Interest Cost	56	56	27	29
Expected Return on Plan Assets	(77)	(72)	(23)	(20)
Amortization of Transition (Asset) Obligation	-	-	7	7
Amortization of Net Actuarial Loss	13	4	7	9
Net Periodic Benefit Cost (Credit)	$ 15	$ 10	$ 29	$ 35

The following table provides the net periodic benefit cost (credit) for the plans by the following Registrant Subsidiaries for the three months ended March 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in thousands)			
APCo	$ 1,848	$ 318	$ 5,345	$ 6,462
CSPCo	534	(407)	2,222	2,765
I&M	2,365	1,114	3,631	4,313
KPCo	376	144	603	742
OPCo	1,206	(105)	3,827	4,801
PSO	72	700	1,869	2,110
SWEPCo	364	901	1,837	2,101
TCC	(219)	746	2,008	2,535
TNC	41	338	877	1,073

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, retired and principal payments made during the first three months of 2005 were:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Issuances:				
APCo	Senior Unsecured Notes	$ 200,000	4.95%	2015
OPCo	Installment Purchase Contracts	54,500	Variable	2029
OPCo	Installment Purchase Contracts	163,500	Variable	2028
TCC	Installment Purchase Contracts	161,700	Variable	2030

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Other Debt	$ 2	13.718%	2026
OPCo	Installment Purchase Contracts	102,000	6.375%	2029
OPCo	Installment Purchase Contracts	80,000	Variable	2028
OPCo	Installment Purchase Contracts	36,000	Variable	2029
OPCo	Notes Payable	1,463	6.81%	2008
OPCo	Notes Payable	3,250	6.27%	2009
SWEPCo	Notes Payable	1,707	4.47%	2011
SWEPCo	Notes Payable	750	Variable	2008
TCC	Senior Unsecured Notes	150,000	3.00%	2005
TCC	Senior Unsecured Notes	100,000	Variable	2005
TCC	Securitization Bonds	29,386	3.54%	2005

During the first quarter of 2005, there were no intercompany issuances and retirements of debt due to affiliates.

Other Matters

On January 3, 2005, the following outstanding shares of preferred stock were redeemed:

Company	Series	Number of Shares Redeemed	Amount (in millions)
I&M	5.900%	132,000	$ 13
I&M	6.250%	192,500	19
I&M	6.875%	157,500	16
I&M	6.300%	132,450	13
OPCo	5.900%	50,000	5
			$ 66

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either 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, 2007 for short-term borrowings sufficient to fund the Utility Money Pool and the Nonutility Money Pool as well as its own requirements in an amount not to exceed $7.2 billion. The Utility Money Pool participants' money pool activity and corresponding SEC authorized limits for the quarter ended March 31, 2005 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of March 31, 2005	SEC Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 45,694	$ -	$ 14,635	$ -	$ (7,131)	$ 125,000
APCo	236,798	43,410	98,844	20,228	29,054	600,000
CSPCo	-	181,238	-	140,718	59,416	350,000
I&M	96,437	11,768	29,964	5,797	(95,967)	500,000
KPCo	-	35,779	-	24,411	24,734	200,000
OPCo	-	182,495	-	115,400	41,407	600,000
PSO	55,009	-	21,550	-	(39,588)	300,000
SWEPCo	-	68,537	-	51,062	40,033	350,000
TCC	238,693	120,937	78,646	49,350	(238,693)	600,000
TNC	-	75,045	-	48,416	52,736	250,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool for the quarter ended March 31, 2005 were 2.96% and 1.63%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the quarter ended March 31, 2005 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
	(in percentages)	
AEGCo	2.00	-
APCo	1.96	2.15
CSPCo	-	2.10
I&M	2.14	2.12
KPCo	-	2.15
OPCo	-	2.14
PSO	2.11	-
SWEPCo	-	2.13
TCC	2.27	2.12
TNC	-	2.14

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the management's discussion and analysis of Registrant Subsidiaries. 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 Combined Management's Discussion and Analysis of Registrants Subsidiaries section of the 2004 Annual Report should be read in conjunction with this report.

Significant Factors

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005. SECA billings by PJM crediting AEP for their SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Ohio Regulatory Activity

Ohio Restructuring

In January 26, 2005 the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter of 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

IGCC Plant

On March 18, 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $18 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover approximately $237 million in construction financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their Rate Stabilization Plans. In Phase 3, which begins when the plant enters commercial operation, projected to be in mid-2010, the Ohio companies would recover the projected $1.0 billion cost of the plant and a return on the unrecovered cost over its operating life along with fuel, replacement power and operation and maintenance costs.

Litigation

Registrant Subsidiaries continue to be involved in various litigation matters as described in the "Significant Factors – Litigation" section of the Combined Management's Discussion and Analysis of Registrant Subsidiaries in the 2004 Annual Report. The 2004 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 2004 Annual Report, but may have a material impact on future results of operations, cash flows and financial condition. Other matters described in the 2004 Annual Report that did not have significant changes during the first quarter of 2005, that should be read in order to gain a full understanding of the current litigation include disclosure related to Coal Transportation Dispute and 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.

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 nonbinding 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 nonbinding court-sponsored mediation.

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. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows or financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

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 nonaffiliated 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.

Environmental Matters

As discussed in the 2004 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:

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

This discussion updates certain events occurring in 2005. You should also read the "Significant Factors – Environmental Matters" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries in the 2004 Annual Report for a description of all environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) the Comprehensive Environmental Response Compensation and Liability Act (Superfund) and state remediation, (4) global climate change, (5) carbon dioxide public nuisance claims, (6) costs for spent nuclear fuel disposal and decommissioning, and (7) Clean Water Act regulation.

Future Reduction Requirements for SO_2, NO_x, and Mercury

Regulatory Emissions Reductions

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

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the Eastern 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.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

On March 14, 2005, the Administrator of the Federal EPA signed the final CAIR. The rule is slightly revised from the proposed version released in January 2004, and includes both a seasonal and annual NO_x control program as well as an annual SO_2 control program. All of the states in which the Registrant Subsidiaries' generating facilities are located will be subject to the regional and annual NO_x control programs and the annual SO_2 control program, except for Texas, Oklahoma and Arkansas. Texas will be subject to the annual programs only. Arkansas will be subject to the seasonal NO_x control program only. Oklahoma is not affected by CAIR. In addition, the compliance deadline for Phase I for the NO_x control program has been accelerated to 2009, and will replace any obligations imposed by the NO_x State Implementation Plan (SIP) Call in 2009.

On March 15, 2005, the Administrator of the Federal EPA signed a final Clean Air Mercury Rule (CAMR) that will 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. The final CAMR imposes a national cap on mercury emissions from coal-fired power plants of 38 tons by 2010 and 15 tons by 2018.

The changes in the Federal EPA's final CAIR and CAMR have not caused us to revise our estimates of the capital investments necessary to achieve compliance with these requirements. However, final rules give states substantial discretion in developing their rules to implement these cap-and-trade programs, and states 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. If states elect not to participate in the federal cap-and-trade programs, or elect to impose additional requirements on individual units that are already subject to CAIR and/or the CAMR, our costs could increase significantly. The cost of compliance could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review Litigation

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

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated 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 occurred 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 filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. The Federal EPA and the states each have filed an additional complaint alleging violations of the new source review requirements at units at the Amos and Conesville plants that were not allowed to be added to the pending case. These separate complaints have been assigned to the same judge in the Southern District Court.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the U.S. District Court for the Southern District of Ohio alleging that violations of the prevention of significant deterioration and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against the Tennessee Valley Authority (TVA), the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. Management believes the allegations in the complaint are without merit, and intends to defend vigorously this action. 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.

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 subsidiaries 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.

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 CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, 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. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May.

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 value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 2005, TCEQ issued an Executive Director’s Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo’s permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

Emergency Release Reporting

Superfund requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances that cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCo's Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

CONTROLS AND PROCEDURES

During the first quarter of 2005, 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. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

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

There was no change in AEP's internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2005 that materially affected, or is reasonably likely to materially affect, AEP's internal controls 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. Unregistered Sales of Equity Securities and Use of Proceeds

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
01/01/05 – 01/31/05	-	$ -	-	$ -
02/01/05 – 02/28/05	-	-	-	(b)
03/01/05 – 03/31/05	12,500,000	34.63	12,500,000	-
Total	12,500,000	$ 34.63	12,500,000	$ (b)

(a) The repurchase was funded with available cash on hand.
(b) In February 2005, AEP's board of directors authorized the repurchase of outstanding common shares of AEP up to an aggregate purchase price of $500 million.

On March 9, 2005, AEP announced the repurchase of 12.5 million shares of its outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share, for a total of approximately $433 million. The 12.5 million shares repurchased under the program are subject to a future contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period which ends in May 2005.

As of April 29, 2005, the counterparty to the agreement had repurchased 95.2% of the shares under the program at an average price per share of approximately $34.12. Assuming the counterparty repurchased the remaining shares at a price per share of $35.22, which was the closing price of AEP's common stock on April 29, 2005, AEP would receive a payment of approximately $5.7 million from the counterparty (excluding expenses and related items). The settlement amount can increase or decrease depending upon the actual price paid for the shares repurchased by the counterparty under the program. The settlement is expected to occur in May 2005.

Item 5. Other Information

NONE

Item 6. Exhibits

AEP

4(a) – Purchase Agreement dated as of March 8, 2005, between AEP and Merrill Lynch International.
10(b) – AEP Retainer Deferral Plan for Non-Employee Directors' effective January 1, 2005, as amended March 10, 2005 *(previously known as AEP Deferred Compensation and Stock Plan for Non-Employee Directors)*.
31(a) – Certification of AEP Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(c) – Certification of AEP Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, OPCo

10(a) – Form of Restricted Stock Unit Agreement furnished to participants of the AEP System 2000 Long-term Incentive Plan, as amended.

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

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

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

31(b) – Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(d) – Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

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

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: May 4, 2005

EXHIBIT 31(a)
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.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and we have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d. 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;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2005

By: /s/ Michael G. Morris
Michael G. Morris
Chief Executive Officer

EXHIBIT 31(b)
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:

AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) for the registrant and we have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2005

By: /s/ Michael G. Morris
Michael G. Morris
Chief Executive Officer

EXHIBIT 31(c)
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.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and we have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d. 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;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2005

By: /s/ Susan Tomasky
Susan Tomasky
Chief Financial Officer

EXHIBIT 31(d)
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:

AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

    c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2005

By: /s/ Susan Tomasky
Susan Tomasky
Chief Financial Officer

Exhibit 32(a)

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 (the “Reports”) for the quarterly period ended March 31, 2005 as filed with the Securities and Exchange Commission on the date hereof, I, Michael G. Morris, the chief executive officer of

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

(the “Companies”), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Michael G. Morris
Michael G. Morris
Chief Executive Officer

May 4, 2005

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(b)

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 (the "Reports") for the quarterly period ended March 31, 2005 as filed with the Securities and Exchange Commission on the date hereof, I, Susan Tomasky, the chief financial officer of

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky
Susan Tomasky
Chief Financial Officer

May 4, 2005

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.