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, 2006**
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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

*Large accelerated filer _X_* *Accelerated filer ___* *Non-accelerated filer ___*

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

Large accelerated filer ___ *Accelerated filer ___* *Non-accelerated filer _X_*

Indicate by check mark whether the registrants are shell companies (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.

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2005, the last trading date of the registrants' most recently completed second fiscal quarter	**Number of shares of common stock outstanding of the registrants at April 28, 2006**
AEP Generating Company	None	1,000 ($1,000 par value)
AEP Texas Central Company	None	2,211,678 ($25 par value)
AEP Texas North Company	None	5,488,560 ($25 par value)
American Electric Power Company, Inc.	$14,172,701,867	393,914,882 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
March 31, 2006

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 AEP electric generating subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated entities.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing their generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EPACT	Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipe Line Company LP, a former AEP subsidiary that was sold in January 2005.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.

MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the FASB.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

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

EXECUTIVE OVERVIEW

Regulatory Activity

Our significant regulatory activity progressed with the following major developments:

- In January 2006, we implemented our Ohio Rate Stabilization Plans, resulting in increased revenues of $49 million for the three months ended March 31, 2006.
- The Kentucky Public Service Commission approved our $41 million rate case settlement agreement. New rates became effective on March 30, 2006.
- In March 2006, after the February 2006 receipt of an order in our Texas stranded costs proceeding, we filed with the Public Utility Commission of Texas (PUCT) for approval of a financing order to issue $1.8 billion in securitization bonds. We expect an order in June or July 2006.
- In April 2006, the Public Utilities Commission of Ohio (PUCO) approved our recovery of the pre-construction costs for the Integrated Gasification Combined Cycle (IGCC) clean-coal plant in Meigs County, Ohio. The PUCO also ruled that it is reasonable to recover the pre-construction costs of the facility through a provider of last resort recovery mechanism. We subsequently submitted tariffs for PUCO approval related to recovery of our IGCC pre-construction costs.
- In April 2006, we reached a tentative settlement in our APCo and WPCo rate case, subject to approval by the Public Service Commission of West Virginia, providing for a $44 million increase in rates effective July 28, 2006.
- In May 2006, we filed a base rate case in Virginia requesting a net rate increase of $198 million.

Our near-term additional activity includes:

- A TCC competition transition charge (CTC) filing with the PUCT in the second quarter to address a $491 million credit to customers from the True-up Proceeding.
- Issuance of securitization bonds in Texas in the third quarter of 2006.

Fuel Costs

Market prices for coal, natural gas and oil continued increasing in the first quarter of 2006. These increasing fuel costs result from increasing worldwide demand, supply interruptions and uncertainty, anticipation and ultimate promulgation of clean air rules, transportation constraints and other market factors. We manage price and performance risk through a portfolio of contracts of varying durations and other fuel procurement and management activities. Fuel recovery mechanisms exist for about 55% of our fuel costs in our various jurisdictions. Additionally, about 25% of our fuel is used for off-system sales where prices for our power should allow us to recover our cost of fuel. Accordingly, we should recover approximately 80% of fuel cost increases. The remaining 20% of our fuel costs relate primarily to Ohio customers, where fuel is a fixed component of costs included in our rates, but we do not have an active fuel cost recovery adjustment mechanism. Such percentages are subject to change over time based on fuel cost impacts and changes to the recovery adjustment mechanisms at jurisdictions in our individual operating companies. In Indiana, our fuel recovery mechanism is temporarily capped, subject to preestablished escalators, at a fixed rate through June 2007. As a consequence of the cap, we currently expect under recoveries during 2006 and under-recovered $4 million for the quarter ended March 31, 2006. In West Virginia, we received permission to begin deferral accounting for over– or under–recovery of fuel and related costs effective July 1, 2006. In addition, our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans. While these items should help to offset some of the negative impact on our gross margins, we expect an additional eleven to thirteen percent increase in coal costs in 2006.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their major activities were:

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

Our consolidated Income Before Discontinued Operations for the three months ended March 31, 2006 and 2005 were as follows (Earnings and Weighted Average Basic Shares Outstanding in millions):

	2006		2005	
	Earnings	**EPS (c)**	**Earnings**	**EPS (c)**
Utility Operations	$ 365	$ 0.93	$ 353	$ 0.90
Investments – Other	16	0.04	5	0.01
All Other (a)	(2)	(0.01)	(14)	(0.04)
Investments – Gas Operations (b)	(1)	-	10	0.03
Income Before Discontinued Operations	$ 378	$ 0.96	$ 354	$ 0.90
Weighted Average Basic Shares Outstanding		394		393

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

First Quarter of 2006 Compared to First Quarter of 2005

Income Before Discontinued Operations in 2006 increased $24 million compared to 2005 due to increased utility operations revenue primarily related to rate increases in our Ohio jurisdiction as approved by the PUCO in CSPCo's and OPCo's Rate Stabilization Plans (RSP).

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

Utility Operations

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

	Three Months Ended March 31,	
	2006	**2005**
	(in millions)	
Revenues	$ 2,969	$ 2,684
Fuel and Purchased Energy	1,127	923
Gross Margin	1,842	1,761
Depreciation and Amortization	333	318
Other Operating Expenses	846	805
Operating Income	663	638
Other Income (Expense), Net	42	30
Interest Expense and Preferred Stock Dividend Requirements	154	144
Income Tax Expense	186	171
Income Before Discontinued Operations	$ 365	$ 353

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three Months Ended March 31, 2006 and 2005

	2006	2005
Energy Summary	**(in millions of KWH)**	
Retail:		
Residential	12,938	13,224
Commercial	8,909	8,732
Industrial	13,221	12,774
Miscellaneous	589	645
Subtotal	35,657	35,375
Texas Retail and Other	68	228
Total	35,725	35,603
Wholesale	10,844	12,635
Texas Wires Delivery	5,546	5,519

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on results of operations. Cooling degree days and heating degree days in our service territory for the quarters ended March 31, 2006 and 2005 were as follows:

	2006	2005
Weather Summary	**(in degree days)**	
Eastern Region		
Actual – Heating (a)	1,456	1,774
Normal – Heating (b)	1,817	1,811
Actual – Cooling (c)	1	-
Normal – Cooling (b)	3	3
Western Region (d)		
Actual – Heating (a)	658	769
Normal – Heating (b)	972	973
Actual – Cooling (c)	43	20
Normal – Cooling (b)	17	18

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

First Quarter of 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006
Income from Utility Operations Before Discontinued Operations
(in millions)

First Quarter of 2005		$ 353
Changes in Gross Margin:		
Retail Margins	111	
Off-system Sales	(24)	
Other	(6)	
Total Change in Gross Margin		81
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	6	
Gain on Sales of Assets, Net	(46)	
Depreciation and Amortization	(15)	
Taxes Other Than Income Taxes	(1)	
Other Income (Expense), Net	12	
Interest and Other Charges	(10)	
Total Change in Operating Expenses and Other		(54)
Income Tax Expense		(15)
First Quarter of 2006		$ 365

Income from Utility Operations Before Discontinued Operations increased $12 million to $365 million in 2006. The key driver of the increase was an $81 million net increase in Gross Margin, offset in part by a $54 million increase in Operating Expenses and Other and a $15 million increase in Income Tax Expense.

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

- Retail Margins increased $111 million primarily due to the following:
  - A $49 million increase related to new rates implemented in our Ohio jurisdiction as approved by the PUCO in our RSPs;
  - A $28 million increase related to increased usage and customer growth in the industrial and commercial classes;
  - An $11 million increase related to increased usage and customer growth in the residential class; and
  - A $26 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily as a result of new power supply contracts; partially offset by
  - A $25 million decrease in usage related to mild weather. As compared to the prior year, heating degree days were 18% lower in the east and 14% lower in the west.
- Margins from Off-system Sales for 2006 were $24 million lower than in 2005 due to lower volumes in part from the sale of STP in May 2005 and lower optimization activities.
- Other revenues decreased $6 million primarily due to a decrease in construction activities performed for third parties.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses decreased $6 million primarily due to a decrease in construction activities performed for third parties.
- Gain on Sales of Assets, Net decreased $46 million resulting from 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. In 2005, we received $112 million related to two years of earnings sharing whereas in 2006 we received $70 million related to one year of earnings sharing.
- Depreciation and Amortization expense increased $15 million primarily due to increased Ohio and Texas regulatory asset amortization.
- Other Income (Expense), Net increased $12 million primarily due to capitalized carrying costs on environmental and system reliability capital expenditures for APCo. APCo began capitalizing carrying costs in conjunction with its environmental and reliability costs filing in Virginia in the third quarter of 2005.
- Interest and Other Charges increased $10 million from the prior period primarily due to new debt issued during 2005 and increasing interest rates.
- Income Tax Expense increased $15 million due to the increase in pretax income. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

Investments – Other

First Quarter of 2006 Compared to First Quarter of 2005

Income Before Discontinued Operations from our Investments – Other segment increased from $5 million in 2005 to $16 million in 2006. The increase was primarily due to favorable barging activity at AEP MEMCO LLC due to strong demand and a tight supply of barges which increased the barge fees. Additionally, the first quarter of 2006 operating conditions for our barging operations improved from 2005 when severe ice and flooding caused increased operating costs.

Other

Parent

First Quarter of 2006 Compared to First Quarter of 2005

The parent company's loss decreased $12 million from 2005 primarily due to lower interest expense related to the redemption of $550 million senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

Investments – Gas Operations

First Quarter of 2006 Compared to First Quarter of 2005

The $1 million Loss Before Discontinued Operations compares with $10 million of income recorded for 2005. Prior year results included one month of HPL's operations due to the sale of HPL in January 2005. Current year results primarily relate to gas contracts that were not sold with the gas pipeline and storage assets.

AEP System Income Taxes

The increase in income tax expense of $17 million between the first quarter of 2006 and first quarter of 2005 is primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

FINANCIAL CONDITION

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

Debt and Equity Capitalization ($ in millions)

	March 31, 2006		December 31, 2005	
Common Equity	$ 9,384	43.0%	$ 9,088	42.5%
Preferred Stock	61	0.3	61	0.3
Long-term Debt, including amounts due within one year	12,142	55.7	12,226	57.2
Short-term Debt	226	1.0	10	0.0
Total Debt and Equity Capitalization	$ 21,813	100.0%	$ 21,385	100.0%

Our common equity increased primarily due to earnings exceeding the amount of dividends paid in 2006. As a consequence of the capital changes during 2006, we improved our ratio of total debt to total capital from 57.2% to 56.7%.

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

Liquidity

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

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2006, our available liquidity was approximately $2.7 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	276	
Total Liquidity Sources	2,976	
Less: AEP Commercial Paper Outstanding	215	
Letter of Credit Drawn on Credit Facility	31	
Net Available Liquidity	$ 2,730	

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion on terms more economically favorable than the previous agreements. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $200 million as letters of credit, expiring separately in March 2010 and April 2011. We also terminated an existing $200 million letter of credit facility. If the amendments had occurred prior to March 31, 2006 our Net Available Liquidity would have been $3,030 million.

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, 2006, this contractually-defined percentage was 53.6%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 2006, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

We do not believe that our rights under the amended facilities would be affected by a material adverse change.

Under a regulatory order, 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 the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At March 31, 2006, all utility subsidiaries were in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 2006, our utility subsidiaries had not exceeded those authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2006 and AEP is currently on a stable outlook by the rating agencies. Our current credit ratings are as follows:

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

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

Cash Flow

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

	Three Month Ended March 31, 2006	**Three Month Ended March 31, 2005**
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 401	$ 320
Net Cash Flows From Operating Activities	590	667
Net Cash Flows From (Used For) Investing Activities	(757)	842
Net Cash Flows From (Used For) Financing Activities	42	(568)
Net Increase (Decrease) in Cash and Cash Equivalents	(125)	941
Cash and Cash Equivalents at End of Period	$ 276	$ 1,261

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of March 31, 2006, we had credit facilities totaling $2.5 billion to support our commercial paper program. In April 2006, we increased our credit facilities to $3 billion. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders.

Operating Activities

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in millions)	
Net Income	$ 381	$ 355
Less: Income From Discontinued Operations	(3)	(1)
Income From Continuing Operations	378	354
Noncash Items Included in Earnings	317	325
Changes in Assets and Liabilities	(105)	(12)
Net Cash Flows From Operating Activities	$ 590	$ 667

<u>2006 Operating Cash Flow</u>

Net Cash Flows From Operating Activities were $590 million in 2006. We produced Income from Continuing Operations of $378 million. Income from Continuing Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased due to recovery of higher cost of fuel, especially natural gas. 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 $99 million cash increase from net Accounts Receivable/Accounts Payable due to a lower balance of Customer Accounts Receivable at March 31, 2006 and an increase in Accrued Taxes of $176 million. We did not make a federal income tax payment during the first quarter of 2006.

<u>2005 Operating Cash Flow</u>

Net Cash Flows From Operating Activities were $667 million in 2005 consisting of our Income from Continuing Operations of $354 million and noncash charges of $327 million for Depreciation and Amortization. We realized gains of $115 million on sales of assets. Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant is a $245 million increase in Accrued Taxes. We did not make a federal income tax payment during the first quarter of 2005.

Investing Activities

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in millions)	
Construction Expenditures	$ (772)	$ (434)
Change in Other Temporary Cash Investments, Net	27	(9)
Investment Securities:		
Purchases of Investment Securities	(2,469)	(1,311)
Sales of Investment Securities	2,380	1,396
Change in Investment Securities, Net	(89)	85
Proceeds from Sales of Assets	111	1,184
Other	(34)	16
Net Cash Flows From (Used for) Investing Activities	$ (757)	$ 842

Net Cash Flows Used For Investing Activities were $757 million in 2006 primarily due to Construction Expenditures. Construction Expenditures increased due to our environmental investment plan.

During 2006, we purchased $2.5 billion of investments and received $2.4 billion of proceeds from the sales of securities. During 2005, we purchased $1.3 billion of investments and received $1.4 billion of proceeds from the sales of securities. We purchase auction rate securities and variable rate demand notes with cash available for short-term investments. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows From Investing Activities were $842 million in 2005 primarily due to the proceeds from the sale of HPL. During 2005, we sold HPL and used a portion of the proceeds from the sale to repurchase common stock. Our Construction Expenditures of $434 million included environmental, transmission and distribution investment.

We forecast $2.9 billion of Construction Expenditures for the remainder of 2006. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	Three Months Ended March 31,	
	2006	2005
	(in millions)	
Issuance of Common Stock	$ 5	$ 17
Repurchase of Common Stock	-	(434)
Issuance/Retirement of Debt, Net	129	65
Dividends Paid on Common Stock	(146)	(138)
Other	54	(78)
Net Cash Flows From (Used for) Financing Activities	$ 42	$ (568)

Net Cash Flows From Financing Activities in 2006 were $42 million. During the first quarter of 2006, we issued $50 million of obligations relating to pollution control bonds and increased our short-term commercial paper outstanding. See Note 12 for a complete discussion of long-term debt issuances and retirements. The Other amount of $54 million in the above table primarily consists of $68 million received from a coal supplier related to a long-term coal purchase contract amended in March 2006.

Net Cash Flows Used For Financing Activities in 2005 were $568 million. During the first quarter of 2005, we repurchased common stock using a portion of the proceeds from the sale of HPL. In addition, our subsidiaries retired $66 million of cumulative preferred stock, which is reflected in the Other amount in the above table.

In April 2006, APCo issued $500 million of debt consisting of $250 million of 5.55% notes due 2011 and $250 million of 6.375% notes due 2036. Also in April, OPCo issued obligations relating to auction rate pollution control bonds in the amount of $65 million. The new bonds bear variable interest at a 28-day auction rate. The proceeds from this issuance will contribute to our investment in environmental equipment.

<u>Off-balance Sheet Arrangements</u>

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to 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 "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" "Financing Activities" above.

Other

Texas REPs

As part of the purchase and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In March of 2006, we received a $70 million payment for our share in earnings for 2005. The payment for 2006 is contingent on Centrica's future operating results, is capped at $20 million and, to the extent payable, will be paid in the first quarter of 2007. See "Texas REPs" section of Note 8.

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the "Significant Factors" section of Management's Financial Discussion and Analysis of Results of Operations in our 2005 Annual Report. The 2005 Annual Report should be read in conjunction with this report in order to understand significant factors without material changes in status since the issuance of our 2005 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

Texas Regulatory Activity

Texas Restructuring

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was $1.475 billion, which included carrying costs through September 2005. TCC filed an application in March 2006 requesting to securitize $1.8 billion of net stranded generation plant costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which are partially offsetting in nature. These obligations total $491 million and would be payable through a CTC over a period determined by the PUCT. Intervenors and the PUCT staff filed testimony in April 2006. Hearings are scheduled for May. It is possible that the PUCT could reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, a negative impact on the timing of cash flows could result. Cash flows from securitization would be adversely impacted if the PUCT reduces TCC's computation of the amount to be securitized in the securitization proceeding.

The PUCT has not addressed the allocation of stranded costs to TCC's wholesale jurisdiction. TCC estimates the amount allocated to wholesale to be less than $1 million, while intervenors and PUCT staff filed testimony recommending that $77 million of stranded costs be allocated to TCC's wholesale jurisdiction. TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize or recover.

Consistent with certain prior securitization determinations, the PUCT may deduct the cost-of-money benefit of accumulated deferred federal income taxes (ADFIT) from the securitization request. Then, the future cost-of-money benefit would be transferred to a separate regulatory asset recoverable in normal delivery rates outside of the securitization process, which would affect the timing of cash recovery. We estimate the total cost-of-money benefit to be $328 million, which TCC plans to include in its estimated CTC request. Intervenors filed testimony recommending an increase in this amount, along with the retrospective ADFIT amounts, by as much as $175 million.

In addition, the intervenors raised three issues totaling $138 million that were addressed by the PUCT in prior proceedings - the appropriate interest rate for both stranded cost and deferred fuel and the treatment of excess earnings refunds. Other issues raised by the intervenors dealt with the amounts to be securitized versus refunded to customers through the CTC, customer class allocation issues and debt defeasance strategies.

The difference between the recorded securitizable true-up regulatory asset of $1.5 billion at March 31, 2006 and our securitization request of $1.8 billion is detailed in the table below:

	(in millions)
Stranded Generation Plant Costs	$ 969
Net Generation-related Regulatory Asset	249
Excess Earnings	(49)
Recorded Net Stranded Generation Plant Costs	1,169
Recorded Debt Carrying Costs on Recorded Net Stranded Generation Plant Costs	284
Recorded Securitizable True-up Regulatory Asset	1,453
Unrecorded But Recoverable Equity Carrying Costs	212
Unrecorded Estimated April 2006 – August 2006 Debt Carrying Costs	40
Unrecorded Securitization Issuance Costs	24
Unrecorded Excess Earnings, Related Return and Other	75
Securitization Request	$ 1,804

The principal components of the CTC rate reduction are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance. TCC will incur carrying costs on the net negative other true-up regulatory liability balances until fully refunded. TCC anticipates filing to implement a negative CTC (as a rate reduction) for its net other true-up items in the second quarter of 2006.

The difference between the components of TCC's recorded net regulatory liabilities – other true-up items as of March 31, 2006 and the amount expected to be requested in the CTC proceeding are detailed below:

	(in millions)
Wholesale Capacity Auction True-up	$ 61
Carrying Costs on Wholesale Capacity Auction True-up	17
Retail Clawback	(61)
Deferred Over-recovered Fuel Balance	(177)
Recorded Net Regulatory Liabilities – Other True-up Items	(160)
ADFIT Benefit	(328)
Unrecorded Carrying Costs and Other	(3)
Estimated CTC Request	$ (491)

If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of such nonrecovery, we would record a provision for such amount which could have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. It is expected that the cities and other intervenors will also pursue vigorously court appeals to further reduce TCC's true-up recoveries. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings, requested rehearings or court appeals. If the municipal customers and other intervenors succeed in their expected appeals, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Litigation

In the ordinary course of business, we and our subsidiaries are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, Note 7 – Commitments and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2005 Annual Report. Additionally, see Note 3 – Rate Matters, Note 4 –

Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies included herein. An adverse result in these proceedings has the potential to materially affect the results of operations, cash flows and financial condition of AEP and its subsidiaries.

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

Environmental Matters

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

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

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. All of these matters are discussed in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2005 Annual Report.

Clean Air Act Requirements

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

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

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

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

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

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

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

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

Estimated Air Quality Environmental Investments

As discussed in the 2005 Annual Report, the CAIR and CAMR programs described above will require us to make significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Our estimates disclosed in the 2005 Annual Report, are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation, required levels of reductions, methods for allocation of allowances and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty.

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

Potential Regulation of CO_2 Emissions

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

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was challenged in the courts and upheld. A petition to appeal to the U.S. Supreme Court has been filed. While mandatory requirements to reduce CO_2 emissions at our power plants do not appear to be imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases have been resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued. A bench trial on remedy issues is scheduled for January 2007.

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

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues have been filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule and the Federal EPA filed a petition for rehearing in that case. The Federal EPA also recently proposed a rule that would define “emissions increases” in a way that most of the challenged activities would be excluded from NSR.

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

Other Environmental Concerns

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2005 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.

Adoption of New Accounting Pronouncements

Beginning in 2006, we adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, the trend in our quarter-over-quarter net income and earnings per share is not materially different. As of March 31, 2006, we have $46 million of total unrecognized compensation cost related to unvested share-based compensation arrangements. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.67 years. See Note 2 – New Accounting Pronouncements in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. These risks include commodity price risk, interest rate risk and credit risk. In addition, because we procure some services and materials in our energy business from foreign suppliers we have foreign currency exchange risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

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

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

We have policies and procedures that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies are 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 various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other senior financial and operating managers.

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

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

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value included in our condensed balance sheet as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
March 31, 2006
(in millions)

	Utility Operations	Investments - Gas Operations	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 437	$ 134	$ 571	$ 54	$ 625
Noncurrent Assets	449	199	648	7	655
Total Assets	886	333	1,219	61	1,280
Current Liabilities	(379)	(139)	(518)	(21)	(539)
Noncurrent Liabilities	(293)	(204)	(497)	(3)	(500)
Total Liabilities	(672)	(343)	(1,015)	(24)	(1,039)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 214	$ (10)	$ 204	$ 37	$ 241

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2006
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ (19)	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5)	7	2
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	-	1
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(4)	-	(4)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	1	-	1
Changes in Fair Value due to Market Fluctuations During the Period (b)	8	2	10
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(2)	-	(2)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2006	$ 214	$ (10)	204
Net Cash Flow and Fair Value Hedge Contracts			37
Ending Net Risk Management Assets at March 31, 2006			$ 241

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, 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, 2006
(in millions)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 38	$ (1)	$ 3	$ -	$ -	$ -	$ 40
Prices Provided by Other External Sources – OTC Broker Quotes (a)	13	39	28	23	-	-	103
Prices Based on Models and Other Valuation Methods (b)	(7)	17	14	14	29	4	71
Total	$ 44	$ 55	$ 45	$ 37	$ 29	$ 4	$ 214
Investments – Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (3)	$ 12	$ -	$ -	$ -	$ -	$ 9
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(1)	(9)	-	-	-	-	(10)
Prices Based on Models and Other Valuation Methods (b)	(2)	-	(1)	(4)	(3)	1	(9)
Total	$ (6)	$ 3	$ (1)	$ (4)	$ (3)	$ 1	$ (10)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ 35	$ 11	$ 3	$ -	$ -	$ -	$ 49
Prices Provided by Other External Sources – OTC Broker Quotes (a)	12	30	28	23	-	-	93
Prices Based on Models and Other Valuation Methods (b)	(9)	17	13	10	26	5	62
Total	$ 38	$ 58	$ 44	$ 33	$ 26	$ 5	$ 204

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

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

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of March 31, 2006

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	21
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	21
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	45
	Physical Forwards	AEP West	45
	Physical Forwards	West Coast	45
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	33
Coal	Physical Forwards	PRB, NYMEX, CSX	33

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2005 to March 31, 2006. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as effective cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Three Months Ended March 31, 2006
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
Changes in Fair Value	22	9	31
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	3	1	4
Ending Balance in AOCI, March 31, 2006	$ 19	$ (11)	$ 8
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 18	$ (1)	$ 17

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of March 31, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 3.13%, expressed in terms of net MTM assets and net receivables. As of March 31, 2006, 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	$ 807	$ 145	$ 662	1	$ 87
Split Rating	4	2	2	2	2
Noninvestment Grade	134	125	9	1	8
No External Ratings:					
Internal Investment Grade	85	-	85	1	64
Internal Noninvestment Grade	32	17	15	2	14
Total	$ 1,062	$ 289	$ 773	7	$ 175

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2008. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of March 31, 2006

	Remainder 2006	2007	2008
Estimated Plant Output Hedged	90%	91%	92%

VaR Associated with Risk Management Contracts

Commodity Price Risk

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Three Months Ended March 31, 2006 (in millions)				Twelve Months Ended December 31, 2005 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$6	$3	$2	$3	$5	$3	$1

Interest Rate Risk

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $531 million at March 31, 2006 and $615 million at December 31, 2005. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2006 and 2005
(in millions, except per-share amounts)
(Unaudited)

	2006	2005
REVENUES		
Utility Operations	$ 2,987	$ 2,605
Gas Operations	(18)	357
Other	139	103
TOTAL	3,108	3,065
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	961	789
Purchased Energy for Resale	166	130
Purchased Gas for Resale	-	249
Maintenance and Other Operation	828	837
Gain/Loss on Disposition of Assets, Net	(68)	(115)
Depreciation and Amortization	341	327
Taxes Other Than Income Taxes	191	188
TOTAL	2,419	2,405
OPERATING INCOME	689	660
Interest and Investment Income	8	11
Carrying Costs Income	30	20
Allowance For Equity Funds Used During Construction	6	6
Gain on Disposition of Equity Investments, Net	3	-
INTEREST AND OTHER CHARGES		
Interest Expense	168	173
Preferred Stock Dividend Requirements of Subsidiaries	1	2
TOTAL	169	175
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	567	522
Income Tax Expense	189	172
Minority Interest Expense	-	1
Equity Earnings of Unconsolidated Subsidiaries	-	5
INCOME BEFORE DISCONTINUED OPERATIONS	378	354
DISCONTINUED OPERATIONS, Net of Tax	3	1
NET INCOME	$ 381	$ 355
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	394	393
BASIC EARNINGS PER SHARE		
Income Before Discontinued Operations	$ 0.96	$ 0.90
Discontinued Operations, Net of Tax	0.01	-
TOTAL BASIC EARNINGS PER SHARE	$ 0.97	$ 0.90
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	396	394
DILUTED EARNINGS PER SHARE		
Income Before Discontinued Operations	$ 0.95	$ 0.90
Discontinued Operations, Net of Tax	0.01	-
TOTAL DILUTED EARNINGS PER SHARE	$ 0.96	$ 0.90
CASH DIVIDENDS PAID PER SHARE	$ 0.37	$ 0.35

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in millions)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 276	$ 401
Other Temporary Cash Investments	202	127
Accounts Receivable:		
Customers	673	826
Accrued Unbilled Revenues	315	374
Miscellaneous	45	51
Allowance for Uncollectible Accounts	(33)	(31)
Total Receivables	1,000	1,220
Fuel, Materials and Supplies	776	726
Risk Management Assets	625	926
Margin Deposits	171	221
Regulatory Asset for Under-Recovered Fuel Costs	92	197
Other	107	127
TOTAL	3,249	3,945
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,726	16,653
Transmission	6,477	6,433
Distribution	10,895	10,702
Other (including gas, coal mining and nuclear fuel)	3,146	3,116
Construction Work in Progress	2,538	2,217
Total	39,782	39,121
Accumulated Depreciation and Amortization	14,974	14,837
TOTAL - NET	24,808	24,284
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,213	3,262
Securitized Transition Assets and Other	583	593
Spent Nuclear Fuel and Decommissioning Trusts	1,160	1,134
Investments in Power and Distribution Projects	47	97
Goodwill	76	76
Long-term Risk Management Assets	655	886
Employee Benefits and Pension Assets	1,090	1,105
Other	840	746
TOTAL	7,664	7,899
Assets Held for Sale	44	44
TOTAL ASSETS	$ 35,765	$ 36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,033	$ 1,144
Short-term Debt	226	10
Long-term Debt Due Within One Year	1,061	1,153
Risk Management Liabilities	539	906
Accrued Taxes	829	651
Accrued Interest	180	183
Customer Deposits	415	571
Other	581	842
TOTAL	4,864	5,460
NONCURRENT LIABILITIES		
Long-term Debt	11,081	11,073
Long-term Risk Management Liabilities	500	723
Deferred Income Taxes	4,847	4,810
Regulatory Liabilities and Deferred Investment Tax Credits	2,760	2,747
Asset Retirement Obligations	950	936
Employee Benefits and Pension Obligations	342	355
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	155	157
Deferred Credits and Other	821	762
TOTAL	21,456	21,563
TOTAL LIABILITIES	26,320	27,023
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2006	2005
Shares Authorized	600,000,000	600,000,000
Shares Issued	415,412,203	415,218,830

	2006	2005
(21,499,992 shares were held in treasury at March 31, 2006 and December 31, 2005)	2,700	2,699
Paid-in Capital	4,137	4,131
Retained Earnings	2,520	2,285
Accumulated Other Comprehensive Income (Loss)	27	(27)
TOTAL	9,384	9,088
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 35,765	$ 36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in millions)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 381	$ 355
Less: Income from Discontinued Operations	(3)	(1)
Income from Continuing Operations	378	354
Adjustments for Noncash Items:		
Depreciation and Amortization	341	327
Accretion of Asset Retirement Obligations	15	18
Deferred Income Taxes	7	(19)
Deferred Investment Tax Credits	(7)	(8)
Carrying Costs Income	(30)	(20)
Mark-to-Market of Risk Management Contracts	(9)	27
Deferred Property Taxes	(82)	(82)
Pension Contributions to Qualified Plan Trusts	-	(102)
Fuel Under-Recovery	103	52
Gain on Sales of Assets and Equity Investments, Net	(71)	(115)
Change in Other Noncurrent Assets	73	(60)
Change in Other Noncurrent Liabilities	(5)	(45)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	214	104
Fuel, Materials and Supplies	(50)	64
Accounts Payable	(115)	7
Accrued Taxes	176	245
Customer Deposits	(157)	55
Other Current Assets	69	(8)
Other Current Liabilities	(260)	(127)
Net Cash Flows From Operating Activities	590	667
INVESTING ACTIVITIES		
Construction Expenditures	(772)	(434)
Change in Other Temporary Cash Investments, Net	27	(9)
Purchases of Investment Securities	(2,469)	(1,311)
Sales of Investment Securities	2,380	1,396
Proceeds from Sales of Assets	111	1,184
Other	(34)	16
Net Cash Flows From (Used For) Investing Activities	(757)	842
FINANCING ACTIVITIES		
Issuance of Common Stock	5	17
Repurchase of Common Stock	-	(434)
Change in Short-term Debt, Net	216	(5)
Issuance of Long-term Debt	55	580
Retirement of Long-term Debt	(142)	(510)
Dividends Paid on Common Stock	(146)	(138)
Other	54	(78)
Net Cash Flows From (Used For) Financing Activities	42	(568)
Net Increase (Decrease) in Cash and Cash Equivalents	(125)	941
Cash and Cash Equivalents at Beginning of Period	401	320
Cash and Cash Equivalents at End of Period	$ 276	$ 1,261
SUPPLEMENTARY INFORMATION		
Cash paid for interest (net of capitalized amounts)	$ 159	$ 170
Cash paid (received) for income taxes, net of refunds	13	(57)
Noncash acquisitions under capital leases	20	9
Construction Expenditures Included in Accounts Payable at March 31,	246	146

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in millions)
(Unaudited)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088
Issuance of Common Stock		1	4			5
Common Stock Dividends				(146)		(146)
Other			2			2
TOTAL						8,949
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $19					35	35
Securities Available for Sale, Net of Tax of $10					19	19
NET INCOME				381		381
TOTAL COMPREHENSIVE INCOME						435
MARCH 31, 2006	415	$ 2,700	$ 4,137	$ 2,520	$ 27	$ 9,384

See Condensed Notes to Condensed Consolidated Financial Statements.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2005 Annual Report as incorporated in and filed with our 2005 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.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on our Condensed Consolidated Balance Sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	March 31, 2006	December 31, 2005
	(in millions)	
Securities Available for Sale, Net of Tax	$ 38	$ 19
Cash Flow Hedges, Net of Tax	8	(27)
Minimum Pension Liability, Net of Tax	(19)	(19)
Total	$ 27	$ (27)

At March 31, 2006, we expect to reclassify approximately $17 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. Twenty-one months is the maximum length of time that we hedge our exposure to variability in future cash flows with contracts designated as cash flow hedges.

Stock-Based Compensation Plans

At March 31, 2006, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan. We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including stock options and employee stock purchases based on estimated fair values. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional discussion.

In conjunction with the adoption of SFAS 123R, we changed our method of attributing the value of stock-based compensation to expense from the accelerated multiple-option approach to the straight-line single-option method. Compensation expense for all share-based payment awards granted prior to January 1, 2006 will continue to be recognized using the accelerated multiple-option approach while compensation expense for all share-based payment awards granted on or after January 1, 2006 is recognized using the straight-line single-option method. As stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the first quarter of 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In our pro forma information presented below as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the quarter ended March 31, 2005, no stock option expense was reflected in Net Income as we accounted for stock options using the intrinsic value method under Accounting Principles Board (APB) Opinion No. 25, “Accounting For Stock Issued to Employees.” Under the intrinsic value method, no stock option expense is recognized when the exercise price of the stock options granted equals the fair value of the underlying stock at the date of grant. No options were granted during the first quarter of 2005. For the quarters ended March 31, 2006 and 2005, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director’s stock units. See Note 10 for additional discussion.

Pro Forma Information Under SFAS 123, “Accounting for Stock-Based Compensation,” for Periods Presented Prior to January 1, 2006

The following table shows the effect on our Net Income and Earnings Per Share as if we had applied fair value measurement and recognition provisions of SFAS 123 to stock-based employee and director compensation awards for the three months ended March 31, 2005:

	2005 (in millions, except per share data)
Net Income, as reported	$ 355
Add: Stock-based compensation expense included in reported Net Income, net of related tax effects	2
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(2)
Pro Forma Net Income	$ 355
Earnings Per Share:	
Basic – as Reported	$ 0.90
Basic – Pro Forma (a)	$ 0.90
Diluted – as Reported	$ 0.90
Diluted – Pro Forma (a)	$ 0.90

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

The following table presents our basic and diluted Earnings Per Share (EPS) calculations included in our Condensed Consolidated Statements of Operations:

	Three Months Ended March 31, 2006		**2005**	
	(in millions, except per share data)	$/share		$/share
Earnings applicable to common stock	$ 381		$ 355	
Average number of basic shares outstanding	393.7	$ 0.97	393.1	$ 0.90
Average dilutive effect of:				
Performance Share Units	1.4	(0.01)	0.8	-
Stock Options	0.3	-	0.3	-
Restricted Stock Units	0.1	-	-	-
Restricted Shares	0.1	-	-	-
Average number of diluted shares outstanding	395.6	$ 0.96	394.2	$ 0.90

Our stock option and other equity compensation plans are discussed in Note 10.

Related Party Transactions

	Three Months Ended March 31, 2006		2005
	(in millions)		
AEP Consolidated Purchased Energy:			
Ohio Valley Electric Corporation (43.47% Owned)	$ 55		$ 43
Sweeny Cogeneration Limited Partnership (50% Owned)	34		29
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	7		4

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

On our Condensed Consolidated Statements of Cash Flows, we included purchases and sales of investments within our Spent Nuclear Fuel and Decommissioning Trusts as a component of Investing Activities.

These revisions had no impact on our previously reported results of operations, financial condition or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented in 2006 that we have determined relate to our operations.

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

In December 2004, the FASB issued SFAS 123R. 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 APB Opinion No. 25, "Accounting for Stock Issued to Employees." We recorded an insignificant cumulative effect of a change in accounting principle in the first quarter of 2006 for the effect of initially applying the statement primarily reflected in Maintenance and Other Operation on our Condensed Consolidated Statements of Operation.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards granted after the time of adoption and recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three months ended March 31, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 156 "Accounting for Servicing of Financial Assets – An Amendment of FASB Statement No. 140" (SFAS 156)

In March 2006, the FASB issued SFAS 156. SFAS 156 requires an entity to recognize a servicing asset or servicing liability each time it undertakes an obligation to service a financial asset by entering into a servicing contract in certain situations and requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value, if practicable. SFAS 156 also requires separate presentation of servicing assets and servicing liabilities subsequently measured at fair value in the statement of financial position and additional disclosures for all separately recognized servicing assets and servicing liabilities. The requirements for recognition and initial measurement of servicing assets and servicing liabilities should be applied prospectively to all transactions after the effective date of this statement. This statement will be effective on January 1, 2007. Management has not completed the process of determining the effect of this statement on our financial statements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, earnings per share calculations, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2005 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. The Rate Matters note within our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations and cash flows. Rate proceedings that are not expected to adversely affect future results of operations and cash flows are not included in this report. The following sections discuss current activities and update the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of $21 million of incremental E&R costs incurred from July 2004 through September 2005. Through March 31, 2006, APCo deferred $26 million of incurred E&R costs.

In January 2006, the Virginia SCC staff proposed that APCo recover current, rather than past, incremental E&R costs in its electric rates at an ongoing level of $20 million. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were established as a regulatory asset. We believe the staff's position is contrary to the statute and an October 2005 Virginia SCC order, which denied APCo's original request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs that the commission found prudent.

Hearings concluded in March 2006. At the hearings, the staff amended its testimony to recommend a $24 million increase in APCo's ongoing rates. If the Virginia SCC reverses its position and adopts the staff's recommendation or denies recovery of any of APCo's deferred E&R costs, future results of operations and cash flows could be adversely impacted.

APCo Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including an equity return. In addition, APCo requested to move off-system sales margins currently credited to customers through base rates to the fuel factor where they can be adjusted annually. This proposed off-system sales rate credit of $27 million partially offsets the $225 million requested increase in base rates for a net increase in revenues of $198 million. APCo requested that the new rates be implemented on an interim basis beginning in the June 2006 customer billings. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

APCo and WPCo West Virginia Rate Case

In April 2006, APCo and WPCo reached agreement with the WVPSC staff and intervenors in the West Virginia rate case filed in 2005. The parties filed a settlement agreement with the WVPSC, providing for an initial overall increase in rates of $44 million effective July 28, 2006. The initial annual increase in rates is comprised of :

- An Expanded Net Energy Cost (ENEC) increase of $56 million for fuel and purchased power expenses;
- A $23 million special construction surcharge providing recovery of the costs of the Wyoming-Jacksons Ferry 765 kV line and scrubbers to date;
- A general base rate reduction of $18 million of which $9 million relates to a reduction in depreciation expense which affects cash flows but not earnings; and
- A $17 million credit for prior over-recoveries of ENEC costs, currently recorded in regulatory liabilities on the Condensed Consolidated Balance Sheets. Therefore, this item impacts cash flows but has no effect on earnings.

In addition, the agreement provides a mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery of the ongoing investments in scrubbers at APCo's Mountaineer and John Amos power plants. The estimated future annual increases based on the level of incremental investment in the scrubbers as proposed in the settlement, are projected to result in a $36 million increase in revenues effective July 1, 2007, a $14 million increase in revenues effective July 1, 2008 and an $18 million increase in revenues effective July 1, 2009. The settlement further provides for the reinstatement of ENEC proceedings and its related annual rate adjustment mechanism for changes in fuel and purchased power costs. Although the agreement is comprehensive in all respects, one issue regarding the rates for a special contract industrial customer remains unresolved. The WVPSC ordered legal briefs to be filed by May 4, 2006 with responses to be filed by May 15, 2006. At this time, the WVPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues and cash flows.

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC, seeking authorization to revise the book depreciation rates applicable to its electric utility plant in service. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition is not a request for a change in customers' electric service rates. Intervenors filed testimony in March 2006 and I&M filed its rebuttal testimony in April 2006. Hearings are scheduled for May 2006. As proposed by I&M, the book depreciation expense reduction would increase earnings, but would not impact cash flows. If approved by the IURC, I&M will currently adjust its book depreciation expense from the approved effective date forward. Management is unable to predict the outcome of this proceeding.

KPCo Rate Filing

In March 2006, the KPSC approved the settlement agreement in KPCo's 2005 base rate case. The approved agreement provides for a $41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes.

PSO Fuel and Purchased Power and its Possible Impact on AEP East companies and AEP West companies

In 2002, PSO under-recovered $44 million 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 proposed collection of those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 through 2003 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of $27 million to $37 million. In February 2006, the OCC staff filed a report regarding $9 million of the reallocation assigned to wholesale customers. In that report, the OCC staff concluded that the reallocation assigned to wholesale customers has been refunded, thus removing that issue from their recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has jurisdiction over that allocation. The PUCT appealed the ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals and will defend its position vigorously. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs or offsets under-recovered fuel deferrals with additional reallocated off-system sales margins, our future results of operations and cash flows could be adversely affected. However, if the position taken by the federal court in Texas applies to PSO's case, the OCC could be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party may file a complaint at the FERC alleging the allocation of off-system sales margins adopted by PSO is improper which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on future results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Inquiry

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo that they will not further pursue the matter.

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

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court. The cities are appealing the appeals court decision to the Texas Supreme Court. Management cannot predict the outcome of further appeals, but a reversal of the favorable court of appeals decision regarding the loss of load issue could result in the issue being returned to the PUCT for further consideration. If the PUCT were to reverse its decision and order refunds of PTB revenues, it could adversely impact results of operations and cash flows.

RTO Formation/Integration Costs

In 2005, the FERC approved the amortization of approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was $1 million in both the first quarter of 2006 and 2005. As of both March 31, 2006 and December 31, 2005, the AEP East companies had $31 million of deferred unamortized RTO formation/integration costs.

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs not billed by PJM of $2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In 2005, the FERC denied a request we jointly filed with two other utilities to recover deferred PJM-billed integration costs from all load-serving entities in the PJM RTO zone over a ten-year period. Instead, the FERC ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In June 2005, AEP filed a request for rehearing. In October 2005, the FERC granted our rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. In April 2006, a settlement was filed with the FERC that allows recovery of our deferred PJM-billed integration costs from the PJM region over ten years. In addition, the settlement reduced the return on equity component included in our carrying charge rate to 10.5%, which will have an immaterial impact on future results of operations.

We recover the amortization of RTO formation/integration costs billed to our AEP East companies in Ohio for CSPCo and OPCo, and in Kentucky for KPCo. We have not commenced recovery in West Virginia (where APCo filed a settlement agreement in its base rate case with the WVPSC that included the recovery of its amortization of these costs), Virginia (where APCo filed a base rate case which includes recovery of these costs) or Indiana (where I&M is subject to a rate cap until June 30, 2007).

Until APCo and I&M can adjust their retail rates to recover the amortization of both RTO-related deferred costs, results of operations and cash flows will be adversely affected by the amortizations. If the Virginia, West Virginia or Indiana commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs and no appeal is ultimately successful, it would have an adverse impact on future results of operations and cash flows.

Transmission Rate Proceedings at the FERC

<u>*SECA Revenue*</u>

In accordance with FERC orders, we collected SECA rates to mitigate lost through-and-out transmission service (T&O) revenues through March 31, 2006, when SECA rates expired. The FERC set SECA rate issues for hearing and indicated that the SECA rate revenues are subject to refund or surcharge. The AEP East companies recognized net SECA revenues of $35 million and $26 million during the first quarter of 2006 and 2005, respectively. Since the implementation of SECA rates in December 2004 through March 2006, we have recognized net SECA revenues of $174 million. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. The SECA hearings are scheduled to begin in early May 2006. At this time, management is unable to determine the outcome of the FERC's SECA rate proceeding and if it will impact future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement allowing increases to our wholesale transmission rates in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues were eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when our Wyoming-Jacksons Ferry transmission line enters service, currently expected in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided with their owned extra-high-voltage facilities that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under our proposed Highway/Byway rate design, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design. In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include 500 kV and higher existing facilities and some facilities at lower voltages in the Highway rate. Another proposal uses facilities 200 kV or higher in the Highway rate. These alternative Highway/Byway proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM rate design. In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. Hearings were held in April 2006.

The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the transmission-owning AEP East companies. The competing Highway/Byway proposals filed by others would also produce incremental net revenues to the AEP East transmission-owning companies, but at a much lower level. The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal. We cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on our revenues and results of operations, compared to the continuation of the PJM rates that went into effect on April 1, 2006 when the SECA rates expired.

As of March 31, 2006, SECA transition rates did not fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through retail rate proceedings. The status of the retail rate proceedings are as follows:

- In Kentucky, KPCo settled a rate case, which provides for the recovery of the transmission revenue shortfall.
- APCo filed a settlement agreement in West Virginia, which included recovery of the lost T&O/SECA transmission revenues.
- A pending rate request filed in February 2006 in Ohio addresses the significant reduction in FERC transmission revenues.
- In Virginia, APCo filed a request for revised rates, which includes recovery of the lost T&O/SECA transmission revenues.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.

Management is unable to predict whether the FERC will approve a regional rate to mitigate the loss of T&O/SECA revenues, or if not, when, and if, the effect of the loss of T&O/SECA transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates, or the FERC's review of our previously collected SECA rates results in a refund to customers.

Allocation Agreement between AEP East companies and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved our proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of cost recovery mechanisms by state; however, in general, it is expected to have a favorable effect on future results of operations and cash flows. Our total trading and marketing margins are unaffected by the allocation methodology.

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 2005 Annual Report should be read in conjunction with this report 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 2005 Annual Report.

TEXAS RESTRUCTURING

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was $1.475 billion, which included carrying costs through September 2005. An order on rehearing was issued by the PUCT in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. We expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties may appeal the PUCT's order claiming it permits TCC to over-recover its stranded costs.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting to securitize $1.8 billion of net stranded generation plant costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which are partially offsetting in nature. These obligations total $491 million and would be payable through a CTC over a period determined by the PUCT. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony in April 2006. Hearings are scheduled for May. It is possible that the PUCT could reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, a negative impact on the timing of cash flows could result. Cash flows from securitization would be adversely impacted if the PUCT reduces TCC's computation of the amount to be securitized.

The PUCT has not addressed the allocation of stranded costs to TCC's wholesale jurisdiction. TCC estimates the amount allocated to wholesale to be less than $1 million, while intervenors and PUCT staff filed testimony recommending that $77 million of stranded costs be allocated to TCC's wholesale jurisdiction. TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize or recover.

Consistent with certain prior securitization determinations, the PUCT may deduct the cost-of-money benefit of accumulated deferred federal income taxes (ADFIT) from the securitization request. Then, the future cost-of-money benefit would be transferred to a separate regulatory asset recoverable in normal delivery rates outside of the securitization process, which would affect the timing of cash recovery. We estimate the total cost-of-money benefit to be $328 million, which TCC plans to include in its estimated CTC request. Intervenors filed testimony recommending an increase in this amount, along with the retrospective ADFIT amounts, by as much as $175 million.

In addition, the intervenors raised three issues totaling $138 million which were addressed by the PUCT in prior proceedings - the appropriate interest rate for both stranded cost and deferred fuel and the treatment of excess earnings refunds. Other issues raised by the intervenors dealt with the amounts to be securitized versus refunded to customers through the CTC, customer class allocation issues and debt defeasance strategies.

The difference between the recorded securitizable true-up regulatory asset of $1.5 billion at March 31, 2006 and our securitization request of $1.8 billion is detailed in the table below:

	(in millions)
Stranded Generation Plant Costs	$ 969
Net Generation-related Regulatory Asset	249
Excess Earnings	(49)
Recorded Net Stranded Generation Plant Costs	1,169
Recorded Debt Carrying Costs on Recorded Net Stranded Generation Plant Costs	284
Recorded Securitizable True-up Regulatory Asset	1,453
Unrecorded But Recoverable Equity Carrying Costs	212
Unrecorded Estimated April 2006 – August 2006 Debt Carrying Costs	40
Unrecorded Securitization Issuance Costs	24
Unrecorded Excess Earnings, Related Return and Other	75
Securitization Request	$ 1,804

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up order, the PUCT reduced net stranded generation plant costs by $51 million related to the present value of accumulated deferred investment tax credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers may be a violation of the Internal Revenue Code's normalization provisions. The federal tax statutes require public utilities to "normalize" or synchronize the tax benefits derived from ADITC and EDFIT with the financial and regulatory life of the regulated plant assets that give rise to the benefit. The normalization rules prohibit returning the benefits to ratepayers faster than the underlying assets are recovered for rate purposes. Once these assets are no longer regulated, the normalization provisions do not permit these benefits to be returned to ratepayers. In the true-up order, the PUCT agreed to consider revisiting this issue if the IRS ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded securitizable true-up regulatory asset in the above reconciliation.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. On April 21, 2006 the IRS informed TCC that they are ruling against the PUCT treatment and consider the flowthrough of ADITC and EDFIT a normalization violation.

In a motion for rehearing, TCC asked the PUCT to reconsider its treatment of ADITC and EDFIT in light of the position of the IRS. In its order on rehearing, the PUCT declined to change its treatment. The PUCT withdrew the language stating it would revisit the issue if their treatment was ruled a normalization violation by the IRS and replaced it with an additional explanation of the basis for its original decision. In a motion for a second rehearing filed April 24, 2006, TCC informed the PUCT that the IRS intended to rule adversely on the private letter ruling request.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of March 31, 2006 and also a loss of the accelerated tax depreciation election in the future. Management intends to continue working with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

CTC Proceeding for Other True-up Items

TCC incurs carrying costs on the net negative other true-up regulatory liability balances until fully refunded. The principal components of the CTC rate reduction are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance. TCC anticipates filing to implement a negative CTC (as a rate reduction) for its net other true-up items in the second quarter of 2006.

The difference between the components of TCC's recorded net regulatory liabilities – other true-up items as of March 31, 2006 and its planned CTC proceeding request are detailed below:

	(in millions)
Wholesale Capacity Auction True-up	$ 61
Carrying Costs on Wholesale Capacity Auction True-up	17
Retail Clawback	(61)
Deferred Over-recovered Fuel Balance	(177)
Recorded Net Regulatory Liabilities – Other True-up Items	(160)
ADFIT Benefit	(328)
Unrecorded Carrying Costs and Other	(3)
Estimated CTC Request	$ (491)

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the same ruling should result. The impact of the favorable Federal District court order, if upheld on appeal, could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, it may file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. An unfavorable FERC ruling may result in a reallocation of off-system sales margins from AEP East companies to AEP West companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets Impacting Securitization and CTC Proceedings

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate from its unbundled cost of service rate proceeding. The recorded embedded debt component of the carrying cost rate is 8.12%. Through March 2006, TCC recorded $301 million of debt-related carrying costs ($284 million on stranded generation plant costs impacting the securitization proceeding and $17 million on wholesale capacity auction true-up impacting the CTC proceeding). The remaining equity component of $166 million will be recognized in income as collected. TCC will continue to accrue a debt-related carrying cost until its net true-up regulatory asset is fully recovered. Equity carrying costs are recognized in income as collected.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% overall carrying cost rate on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period from the date of adoption. TCC received an order in the True-up Proceeding in February 2006 and an order on rehearing in April 2006 (which is subject to rehearing). TCC asserted in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order. If adopted retroactively, it would have an adverse effect on future results of operations and cash flows.

Summary

Our recorded securitizable true-up regulatory asset at March 31, 2006 of $1.5 billion, net of regulatory liabilities – other true-up items of $160 million, accurately reflects the PUCT's order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges would be more than sufficient to recover TCC's recorded net true-up regulatory asset. As a result, we have not recorded any additional impairment. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its true-up or subsequent proceedings, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods established by the PUCT in future securitization and CTC proceedings. If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of such nonrecovery, we would record a provision for such amount which could have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. It is expected that municipal customers and other intervenors will also pursue vigorously court appeals to further reduce TCC's true-up recoveries. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings, requested rehearings or court appeals. If municipal customers and other intervenors succeed in their expected appeals, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Texas Restructuring – SPP

In April 2006, the PUCT proposed a possible delay in customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP.

OHIO RESTRUCTURING

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for the IGCC Plant (see "IGCC Plant" section of this note below). OPCo's potential for the additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for the IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $8 million for CSPCo and $20 million for OPCo in the first quarter of 2006 from all the RSP recoveries less the amortization of RSP deferrals net of the recognition of equity carrying charges from 2004 and 2005.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In Dayton Power & Light Company's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In another Ohio Supreme Court decision involving FirstEnergy Corporation's Ohio electric companies, the Court held that the PUCO-approved RSPs for FirstEnergy Corporation's Ohio electric companies did not comply with the statutory provision regarding the availability of a competitive bid alternative for customers. The Ohio companies believe their RSPs are factually different from FirstEnergy Corporation's Ohio electric companies' RSPs and comply with the applicable statute. However, if the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo and OPCo's future earnings will be adversely affected. In addition, if the RSP order were determined on appeal to be illegal in its entirety under the Ohio Electric Restructuring Act of 1999, it would have an initial adverse effect on results of operations, cash flows and possibly financial condition. Although we believe that the RSP plan is legal and we intend to defend vigorously the PUCO's order, we cannot predict the ultimate outcome of the pending litigation.

IGCC Plant

In March 2005, the Ohio companies 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 proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, recovery of construction-financing costs; and Phase 3, recovery, or refund, in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008 under their RSPs. As of March 31, 2006, the Ohio companies deferred $10 million of pre-construction IGCC costs.

On April 10, 2006, the PUCO issued an order finding that the PUCO has the jurisdiction to approve the proposed cost recovery and authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. The Ohio companies filed a tariff to recover Phase 1 pre-construction costs over a twelve-month period. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

Transmission Rate Filing

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month following the date when AEP's Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur on June 30, 2006. We anticipate, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 and increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing intends to recover the new OATT rates resulting from the settlement of our March 2005 filing with the FERC requesting increased OATT rates in a three-step increase. In March 2006, the PUCO suspended the effective date of the new rates to provide its staff additional time to conduct its review of the application. In their application, the Ohio companies requested permission to defer for future recovery their unrecovered transmission costs as a result of the loss of SECA revenues starting April 1, 2006 if the PUCO did not issue an order in this case in time to implement the increase on April 1, 2006. If the PUCO does not approve the future recovery of the unrecovered transmission costs effective April 1, 2006 when the SECA revenues ceased, results of operations and cash flows will be adversely affected.

Storm Cost Recovery Filing

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously-expensed costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately $12 million of such costs.

PUCO Staff Report on Service Reliability

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In April 2006, the staff of the PUCO submitted a commission-ordered investigative report on the Ohio companies' compliance with the stipulation agreement. In the report, the staff asserted that the Ohio companies failed to fulfill all the terms of the stipulation agreement. The staff recommended various consequences for the PUCO's consideration, including the potential for civil forfeitures, monthly payments until the terms of the stipulation agreement have been met and providing credits to customers. The staff also suggested that the PUCO could explore possible improvements in the Ohio companies' management of the reliability process. Finally, the staff recommended that the Ohio companies file, in a companion docket, a comprehensive plan to improve their system reliability. The PUCO ordered the Ohio companies to respond to the staff's recommendations concerning consequences by May 23, 2006, after which the PUCO will determine how to proceed. In the companion docket, the PUCO directed the Ohio companies to prepare a plan to enhance service reliability. A timeline for submission of that plan has not been set. The PUCO indicated that it will set a procedural schedule in the future. Although we believe that the Ohio companies have substantially met the terms and expectations of the stipulation agreement, we cannot predict the outcome of these proceedings. If the PUCO adopts the staff's recommendations, results of operations and cash flows could be adversely affected.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, we defer customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through March 31, 2006, we incurred $101 million of such costs and, accordingly, we deferred $53 million of such costs for probable future recovery in distribution rates. We have not recorded $8 million of equity carrying costs, which are not recognized until collected. Recovery of these regulatory assets is subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSPs, recovery of these amounts is deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2005 Annual Report, we continue to be involved in various legal matters. The 2005 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 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in our 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued. A bench trial on remedy issues is scheduled for January 2007.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer and Stuart stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases have been resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues have been filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule and the Federal EPA filed a petition for rehearing in that case. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal was appealed to the Second Circuit Court of Appeals. Briefing has been completed and the case is scheduled to be argued this summer. We believe the actions are without merit and intend to defend vigorously against the claims.

Ontario Litigation

In June 2005, we and nineteen nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted $NO_{X,}$ SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

OPERATIONAL

Power Generation Facility and TEM Litigation

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

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility. The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper lease, our maximum cash payment could be as much as $525 million. Because we now report Juniper's funded obligations totaling $525 million related to the Facility on our Condensed Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

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

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under the PPA; (ii) would seek a declaration from the District Court that the PPA was terminated; and (iii) would pursue against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM breached the contract and awarded us damages of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (i) award a termination payment to us under the terms of the PPA; (ii) grant our attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional $50 million damage award.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover the claimed termination value damages from TEM.

Enron Bankruptcy

In connection with our 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. The state court of appeals scheduled oral argument on the appeal for June 2006. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

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

New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

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

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter (see Note 8).

Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in Federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We filed a Motion to Dismiss these actions, which the Court denied. The cases are in the discovery stage. The Court scheduled a hearing on class certification for June 2006. We intend to continue to defend vigorously against these claims.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases appealed the decisions. We will continue to defend vigorously each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies, including AEP and AEPES, making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases were consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the Court granted the plaintiffs motion for class certification. The defendants filed a petition for leave to appeal this decision. We intend to continue to defend vigorously against these claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that we sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities' request for a rehearing was denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. GUARANTEES

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

LETTERS OF CREDIT

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At March 31, 2006, the maximum future payments for all the LOCs are approximately $31 million with maturities ranging from July 2006 to March 2007.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $55 million with maturity dates ranging from July 2006 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. At March 31, 2006, the cost to reclaim the mine in 2035 is estimated at 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 enter 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. Prior to March 31, 2006, we entered into several sale agreements. The status of certain sales agreements is discussed in the "Dispositions" section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.3 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of Note 5). 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 receipt of 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 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, 2006, the maximum potential loss for these lease agreements was approximately $52 million ($34 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 BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five 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. We intend to renew the lease for the full twenty years.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the lease term from approximately 86% to 77% of the projected fair market value of the equipment. At March 31, 2006, the maximum potential loss was approximately $31 million ($20 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other rail car lease arrangements that do not utilize this type of structure.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a company-wide staffing and budget review in the second quarter of 2005, we identified approximately 500 positions for elimination. Pretax severance benefits expense of $28 million was recorded (primarily in Maintenance and Other Operation within the Utility Operations segment) in 2005, primarily in the second quarter. The company subsequently made payments of $16 million during 2005. The following table shows the accrual as of December 31, 2005, the activity during the first quarter of 2006 and the remaining accrual (reflected primarily in Current Liabilities – Other) as of March 31, 2006:

	Amount (in millions)
Accrual at December 31, 2005	$ 12
Less: Total Payments	8
Less: Accrual Adjustments	2
Remaining Accrual at March 31, 2006	$ 2

The accrual adjustments were recorded primarily in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations. The settlement of the remaining accrual is expected by the end of the second quarter of 2006.

8. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS

2006

Compresion Bajio S de R.L. de C.V. (Investments – Other segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600-MW power plant in Mexico. We received an indicative offer for Bajio in September 2005. The sale was completed in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

2005

Houston Pipe Line Company LP (HPL) (Investments – Gas Operations segment)

During 2005, we sold our interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of March 31, 2006 and December 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Condensed 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 potential resulting inability to use the cushion gas (see "Enron Bankruptcy" 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 and the cushion gas arrangement. In addition, we continue to hold forward gas contracts not sold with the gas pipeline and storage assets.

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 and was amended through a series of agreements that AEP and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In March 2006, we received a payment of $70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica's future operating results and is capped at $20 million. The payments are reflected in Gain/Loss on Disposition of Assets, Net on our accompanying Condensed Consolidated Statements of Operations.

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 classified as shown in the following table (in millions):

Three Months ended March 31, 2006 and 2005:

	SEEBOARD (a)	U.K. Generation (b)	Total
2006 Revenue	$ -	$ -	$ -
2006 Pretax Income	-	5	5
2006 Earnings, Net of Tax	-	3(c)	3
2005 Revenue (Expense)	$ -	$ (8)	$ (8)
2005 Pretax Loss	-	(8)	(8)
2005 Earnings (Loss), Net of Tax	6	(5)(d)	1

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. Amounts in 2005 relate to purchase price true-up adjustments and tax adjustments from the sale.
(c) Earnings per share related to the UK Operations was $0.01.
(d) Earnings per share related to the UK Operations was $(0.01).

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the three months ended March 31, 2006 and 2005.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsfield (the "nonaffiliated co-owners"). By May 2004, we received notice from the 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 the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in Dallas County, Texas State District Court by Golden Spread. Golden Spread alleges that the Public Utilities Board of the City of Brownsfield exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread on October 10, 2005. TCC and the nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. The case was briefed and argued before the court and is awaiting a decision. 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 related to the Oklaunion Power Station have been classified as Assets Held for Sale on our Condensed Consolidated Balance Sheets at March 31, 2006 and December 31, 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

Assets Held for Sale at March 31, 2006 and December 31, 2005 are as follows:

Texas Plants	**March 31, 2006**	**December 31, 2005**
Assets:	**(in millions)**	
Other Current Assets	$ 1	$ 1
Property, Plant and Equipment, Net	43	43
Total Assets Held for Sale	$ 44	$ 44

9. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the following plans for the three months ended March 31, 2006 and 2005:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2006	**2005**	**2006**	**2005**
	(in millions)			
Service Cost	$ 24	$ 23	$ 10	$ 11
Interest Cost	57	56	25	27
Expected Return on Plan Assets	(83)	(77)	(23)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	20	13	5	7
Net Periodic Benefit Cost	$ 18	$ 15	$ 24	$ 29

10. STOCK-BASED COMPENSATION

The Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value shares awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original Plan in 2000 and the amended and restated version in 2005. Except for 10,000 stock options granted in the third quarter of 2005, we have not granted stock options since 2004. The following sections provide further information regarding each type of stock-based compensation award we have granted.

We adopted SFAS 123R, effective January 1, 2006. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional information.

Stock Options

For all stock options previously granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Historically we have granted stock options with a ten-year term that generally vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Compensation cost for stock options is recorded over the vesting period based on the fair value on the grant date. The Plan does not specify a maximum contractual term for stock options.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled, expired or forfeited. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

AEP did not award any stock options during the three months ended March 31, 2006 and 2005.

The total fair value of stock options vested during the three months ended March 31, 2006 and 2005 were $3,664,624 and $5,030,424, respectively. The total intrinsic value of options exercised during the three months ended March 31, 2006 and 2005 was $1,389,409 and $4,319,995, respectively. Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the three months ended March 31, 2006 is as follows:

	Options		Weighted Average Exercise Price
Outstanding at beginning of quarter	6,221,839	$	34.16
Granted	-		N/A
Exercised/converted	(172,722)		28.67
Expired	(87,611)		48.43
Forfeited	-		N/A
Outstanding at end of quarter	5,961,506		34.11
Options exercisable at end of quarter	5,689,652	$	34.34
Weighted average exercise price of options:			
Granted above Market Price	-	$	N/A
Granted at Market Price	-	$	N/A

The following table summarizes information about AEP stock options outstanding at March 31, 2006.

Options Outstanding

2006 Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value
$25.73 - $27.95	1,465,615	6.9	$	27.37	$	9,693,895
$30.76 - $38.65	4,110,408	4.6		35.45		823,032
$43.79 - $49.00	385,483	5.4		45.52		-
	5,961,506	5.2		34.11	$	10,516,927

The following table summarizes information about AEP stock options exercisable at March 31, 2006.

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value
$25.73 - $27.95	1,260,528	6.1	$	27.29	$	8,473,587
$30.76 - $38.65	4,050,741	3.6		35.50		602,951
$43.79 - $49.00	378,383	5.0		45.49		-
	5,689,652	4.2		34.34	$	9,076,538

The proceeds received from exercised stock options are included in common stock and paid-in capital.

For options issued through December 31, 2005, the grant date fair value of each option award was estimated using a Black-Scholes option-pricing model with weighted average assumptions. Expected volatilities are estimated using the historical monthly volatility of our common stock for the 36-month period prior to each grant. A seven-year average expected term is also assumed. The risk-free rate is the yield for U.S. Treasury securities with a remaining life equal to the expected seven-year term of AEP stock options on the grant date.

Performance Units

Our performance units are equal in value to an equivalent number of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee) and can range from 0 percent to 200 percent. Performance units are typically paid in cash at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units ("AEP Career Shares") until after the end of the participant's AEP career. AEP Career Shares have a value equivalent to the market value of an equal number of AEP common shares and are generally paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and AEP Career Shares is adjusted for changes in value. The vesting period of all performance units is three years.

We awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the three months ended March 31, 2006 and 2005 as follows:

Performance Units	**2006**	**2005**
Awarded Units	864,420	1,012,597
Unit Fair Value at Grant Date	$ 37.36	$ 34.02
Vesting Period (years)	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**2006**	**2005**
Awarded Units	30,277	23,939
Unit Fair Value at Grant Date	$ 35.31	$ 34.21
Vesting Period (years)	3	3

In January 2006, the HR Committee certified a performance score of 49% for performance units originally granted for the 2003 through 2005 performance period. As a result, 108,486 performance units were earned. Of this amount 33,296 were mandatorily deferred as AEP Career Shares, 4,360 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash. The cash payout for these performance units was $2,629,537 for the three months ended March 31, 2006.

The score for the 2002 through 2004 performance period was discretionarily reduced to 0% by the HR Committee so no performance units were earned, paid or deferred during the three months ended March 31, 2005.

The cash payouts for AEP Career Share distributions, which occur after a participant's termination of employment, for the three months ended March 31, 2006 and 2005 were $475,685 and $564,598, respectively.

The performance unit scores for all open performance periods are dependent on two equally weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period.

The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

Restricted Shares and Restricted Stock Units

We granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. The maximum term for these restricted shares is eight years. We have not granted other restricted shares. Dividends on our restricted shares are paid in cash.

We also grant restricted stock units, which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of these restricted stock units is six years.

In January 2006, we also granted restricted stock units with performance vesting conditions to certain employees who are integral to our project to design and build an IGCC power plant. Twenty percent of these awards vest on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operations. The remaining 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

We awarded restricted stock units, including units awarded for dividends, for the three months ended March 31, 2006 and 2005 as follows:

Restricted Stock Units	2006	2005
Awarded Units	37,199	27,100
Weighted Average Grant Date Fair Value	$ 35.80	$ 33.11

The total fair value of restricted shares and restricted stock units vested during the three months ended March 31, 2006 and 2005 were $2,279,551 and $2,132,922, respectively. The total intrinsic value of restricted shares and restricted stock units vested during the three months ended March 31, 2006 and 2005 was $2,944,138 and $2,577,752, respectively.

A summary of the status of our nonvested restricted shares and restricted stock units as of March 31, 2006, and changes during the three months ended March 31, 2006, are presented below:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
Nonvested at beginning of quarter	496,716	$ 32.19
Granted	37,199	35.80
Vested	(78,944)	28.88
Forfeited	(565)	32.81
Nonvested at end of quarter	454,406	33.06

The total aggregate intrinsic value of nonvested restricted shares and restricted stock units as of March 31, 2006 was $15,458,892 and the weighted average remaining contractual life was 3.14 years.

Share-based Compensation Plans

Compensation cost for share-based payment arrangements recognized in income for the three months ended March 31, 2006 and 2005 was $2,429,868 and $2,916,484, respectively. The actual tax benefit realized for the tax deductions from compensation cost from share-based payment arrangements recognized in income for the three months ended March 31, 2006 and 2005 totaled $850,454 and $1,020,769, respectively. The total compensation cost capitalized in relation to the cost of an asset for the three months ended March 31, 2006 and 2005 was $578,434 and $401,159, respectively.

During the three months ended March 31, 2006 and 2005, there were no significant modifications affecting any of our share-based payment arrangements.

As of March 31, 2006, there was $45,936,136 of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the Plan. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.67 years.

Cash received from stock options exercised during the three months ended March 31, 2006 and 2005 was $4,952,298 and $15,153,465, respectively. The actual tax benefit realized for the tax deductions from stock options exercised during the three months ended March 31, 2006 and 2005 totaled $486,293 and $1,515,268, respectively.

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and restricted stock unit vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the Plan or any combination thereof for this purpose. The number of new shares issued to fulfill vesting restricted stock units is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

11. BUSINESS SEGMENTS

As outlined in our 2005 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision that we no longer pursue business interests outside of the footprint of our domestic core utility assets led us to embark on a divestiture of such noncore assets. Consequently, the significance of our three Investments segments has declined.

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- Our gas pipeline and storage assets were disposed of in 2005 with the sale of HPL (see "Dispositions" section of Note 8).

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.
- UK Operations were classified as Discontinued Operations during 2003 and were sold during 2004.

Investments – Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

The tables below present segment income statement information for the three months ended March 31, 2006 and 2005 and balance sheet information as of March 31, 2006 and December 31, 2005. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended March 31, 2006							
Revenues from:							
External Customers	$ 2,987	$ (18)	$ -	$ 139	$ -	$ -	$ 3,108
Other Operating Segments	(18)	21	-	3	1	(7)	-
Total Revenues	$ 2,969	$ 3	$ -	$ 142	$ 1	$ (7)	$ 3,108
Income (Loss) Before Discontinued Operations	$ 365	$ (1)	$ -	$ 16	$ (2)	$ -	$ 378
Discontinued Operations, Net of Tax	-	-	3	-	-	-	3
Net Income (Loss)	$ 365	$ (1)	$ 3	$ 16	$ (2)	$ -	$ 381

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended March 31, 2005							
Revenues from:							
External Customers	$ 2,605	$ 357	$ -	$ 103	$ -	$ -	$ 3,065
Other Operating Segments	79	(73)	-	6	1	(13)	-
Total Revenues	$ 2,684	$ 284	$ -	$ 109	$ 1	$ (13)	$ 3,065
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

	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	All Other	Reconciling Adjustments (b)	Consolidated
				(in millions)			
As of March 31, 2006							
Total Property, Plant and Equipment	$ 38,943	$ 2	$ -	$ 834	$ 3	$ -	$ 39,782
Accumulated Depreciation and Amortization	14,852	1	-	119	2	-	14,974
Total Property, Plant and Equipment – Net	$ 24,091	$ 1	$ -	$ 715	$ 1	$ -	$ 24,808
Total Assets	$ 34,178	$ 830(c)	$ 625(d)	$ 593	$ 10,782	$ (11,243)	$ 35,765
Assets Held for Sale	44	-	-	-	-	-	44
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837
Total Property, Plant and Equipment – Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199(e)	$ 632(f)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44

(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 $830 million for the Investments-Gas Operations segment include $349 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $481 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.

(d) Total Assets of $625 million for the Investments-UK Operations segment include $613 million in affiliated accounts receivable related mainly to federal income taxes that are eliminated in consolidation. The majority of the remaining $12 million in assets represents cash equivalents with value-added tax receivables.

(e) Total Assets of $1.2 billion for the Investments-Gas Operations segment include $429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.

(f) Total Assets of $632 million for the Investments-UK Operations segment include $613 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $19 million in assets represents cash equivalents with value-added tax receivables.

12. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	March 31, 2006	December 31, 2005
	(in millions)	
Pollution Control Bonds	$ 1,985	$ 1,935
Senior Unsecured Notes	8,226	8,226
First Mortgage Bonds	96	196
Defeased First Mortgage Bonds (a)	26	26
Notes Payable	899	904
Securitization Bonds	617	648
Notes Payable To Trust	113	113
Other Long-Term Debt (b)	238	236
Unamortized Discount (net)	(58)	(58)
Total Long-term Debt Outstanding	12,142	12,226
Less Portion Due Within One Year	1,061	1,153
Long-term Portion	$ 11,081	$ 11,073

(a) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $18 million at both March 31, 2006 and December 31, 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments at both March 31, 2006 and December 31, 2005 and $21 million is included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both March 31, 2006 and December 31, 2005. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond had a balance of $8 million at both March 31, 2006 and December 31, 2005. Trust fund assets related to this obligation of $1 million at both March 31, 2006 and December 31, 2005 are included in Other Temporary Cash Investments and $9 million and $8 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at March 31, 2006 and December 31, 2005, respectively. 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. Trust fund assets of $266 million and $264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at March 31, 2006 and December 31, 2005, respectively.

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2006 are shown in the tables below.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 50	Variable	2036
SWEPCo	Notes Payable	6	Variable	2006
Total Issuances		$ 56(a)		

The above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of $55 million is net of issuance costs and unamortized premium or discount.

In April 2006, APCo issued $250 million, 5.55% senior notes due in 2011 and $250 million, 6.375% senior notes due in 2036. The proceeds will be used for general corporate purposes including funding the construction program, repaying advances from affiliates and replenishing working capital.

In April 2006, OPCo incurred obligations of $65 million relating to variable rate pollution control bonds due in 2036. The proceeds will be used to finance the cost of solid waste disposal facilities at the Mitchell Generating Station.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	First Mortgage Bonds	$ 100	6.80	2006
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	2006
SWEPCo	Notes Payable	1	Variable	2008
TCC	Securitization Bonds	31	5.01	2010
Non-Registrant:				
AEP Subsidiaries	Notes Payable	3	Variable	2017
Total Retirements		$ 142		

Credit Facilities

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $200 million as letters of credit, expiring separately in March 2010 and April 2011. We also terminated an existing $200 million letter of credit facility.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of the Rockport Plant, we engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and co-owner of the Rockport Plant.

We derive operating revenues from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC-approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, we accumulate all expenses monthly and prepare bills for our affiliates. In the month the expenses are incurred, we recognize the billing revenues and establish a receivable from the affiliated companies. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income increased $0.4 million for 2006 compared with 2005. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant which are calculated and adjusted monthly.

First Quarter of 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 2.5
Change in Gross Margin:		
Wholesale Sales		2.8
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(1.7)	
Taxes Other Than Income Taxes	(0.1)	
Interest Expense	(0.1)	
Total Change in Operating Expenses and Other		(1.9)
Income Tax Expense		(0.5)
First Quarter of 2006		$ 2.9

Gross Margin, Operating Revenues less Fuel for Electric Generation, increased $2.8 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The increase in Other Operation and Maintenance expenses resulted from increased maintenance cost at Rockport Plant during a planned outage in 2006 and credits allocated to us from the cancellation and settlement of corporate owned life insurance policies in February 2005.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Off-Balance Sheet Arrangements

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only 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 Financial Discussion and Analysis" section of our 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 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
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(Unaudited)
(in thousands)

	2006	2005
OPERATING REVENUES	$ 78,151	$ 66,546
EXPENSES		
Fuel for Electric Generation	43,961	35,135
Rent – Rockport Plant Unit 2	17,071	17,071
Other Operation	3,095	2,447
Maintenance	2,786	1,718
Depreciation and Amortization	5,948	5,956
Taxes Other Than Income Taxes	1,070	1,024
TOTAL	73,931	63,351
OPERATING INCOME	4,220	3,195
Interest Expense	(722)	(634)
INCOME BEFORE INCOME TAXES	3,498	2,561
Income Tax Expense	570	45
NET INCOME	$ 2,928	$ 2,516

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three Months Ended March 31, 2006 and 2005
(Unaudited)
(in thousands)

	2006	2005
BALANCE AT BEGINNING OF PERIOD	$ 26,038	$ 24,237
Net Income	2,928	2,516
Cash Dividends Declared	1,998	940
BALANCE AT END OF PERIOD	$ 26,968	$ 25,813

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

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

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(Unaudited)
(in thousands)

	2006	2005
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	$ 28,064	$ 29,671
Fuel	15,675	14,897
Materials and Supplies	7,283	7,017
Accrued Tax Benefits	-	2,074
Prepayments and Other	44	9
TOTAL	51,066	53,668
PROPERTY, PLANT AND EQUIPMENT		
Electric – Production	688,479	684,721
Other	2,240	2,369
Construction Work in Progress	9,818	12,252
Total	700,537	699,342
Accumulated Depreciation and Amortization	387,933	382,925
TOTAL – NET	312,604	316,417
Noncurrent Assets	9,312	6,618
TOTAL ASSETS	$ 372,982	$ 376,703

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

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 13,317	$ 35,131
Accounts Payable:		
General	1,569	926
Affiliated Companies	19,450	22,161
Long-term Debt Due Within One Year	44,831	44,828
Accrued Taxes	7,160	3,055
Accrued Rent – Rockport Plant Unit 2	23,427	4,963
Other	849	1,228
TOTAL	110,603	112,292
NONCURRENT LIABILITIES		
Deferred Income Taxes	22,659	23,617
Asset Retirement Obligations	1,397	1,370
Regulatory Liabilities and Deferred Investment Tax Credits	82,107	82,689
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	92,941	94,333
Obligations Under Capital Leases	11,873	11,930
TOTAL	210,977	213,939
TOTAL LIABILITIES	321,580	326,231
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $1,000 Par Value Per Share		
Authorized and Outstanding – 1,000 Shares	1,000	1,000
Paid-in Capital	23,434	23,434
Retained Earnings	26,968	26,038
TOTAL	51,402	50,472
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 372,982	$ 376,703

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

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 2,928	$ 2,516
Adjustments for Noncash Items:		
Depreciation and Amortization	5,948	5,956
Deferred Income Taxes	(1,126)	(1,192)
Deferred Investment Tax Credits	(827)	(834)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(1,392)	(1,392)
Deferred Property Taxes	(2,734)	(2,884)
Changes in Other Noncurrent Assets	(376)	(233)
Changes in Other Noncurrent Liabilities	374	448
Changes in Components of Working Capital:		
Accounts Receivable	1,607	(1,170)
Fuel, Materials and Supplies	(1,044)	5,416
Accounts Payable	(2,068)	(2,953)
Accrued Taxes, Net	6,179	359
Accrued Rent – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(35)	(35)
Other Current Liabilities	(379)	(351)
Net Cash Flows From Operating Activities	25,519	22,115
INVESTING ACTIVITIES		
Construction Expenditures	(1,693)	(1,379)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(21,814)	(19,784)
Principal Payments for Capital Lease Obligations	(14)	(12)
Dividends Paid	(1,998)	(940)
Net Cash Flows Used For Financing Activities	(23,826)	(20,736)
Net Change in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $1,109,000 and $1,021,000 and for income taxes net of refunds was $0 and $5,439,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $27,000 and $18,000 in 2006 and 2005, respectively.

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

AEP GENERATING COMPANY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to AEGCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income (in millions)

First Quarter of 2005		$ 1
Changes in Gross Margin:		
Texas Supply	(44)	
Texas Wires	3	
Transmission Revenues	(4)	
Other	(3)	
Total Change in Gross Margin		(48)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	31	
Depreciation and Amortization	(4)	
Taxes Other Than Income Taxes	2	
Carrying Costs on Stranded Cost Recovery	24	
Total Change in Operating Expenses and Other		53
Income Tax Expense		(2)
First Quarter of 2006		$ 4

Net Income increased $3 million in the first quarter of 2006. The key drivers of the increase were a $31 million decrease in Other Operation and Maintenance expenses and increased Carrying Costs on Stranded Cost Recovery of $24 million, partially offset by a decrease in Gross Margin of $48 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel and purchased power were as follows:

- Texas Supply margins decreased $44 million primarily due to lower nonaffiliated sales of $54 million and lower ERCOT energy sales of $4 million. These decreases were partially offset by lower fuel and purchased power expenses of $18 million. We substantially exited the generation market with the sale of STP in May 2005.
- Texas Wires revenues increased $3 million primarily due to an increase in sales volumes resulting in large part from an increase in degree days.
- Transmission Revenues decreased $4 million primarily due to lower ERCOT rates.
- Other revenues decreased $3 million primarily due to lower third party construction project revenues, primarily related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $31 million primarily due to an $8 million decrease in power plant operations, $10 million decrease in plant maintenance and the absence of $5 million in accretion expense related to the sale of STP. An additional $6 million decrease resulted from lower expenses related to construction activities performed for third parties, primarily the Lower Colorado River Authority.
- Carrying Costs on Stranded Cost Recovery increased $24 million primarily due to a $27 million negative adjustment recorded in the first quarter of 2005 related to prior years.

Income Taxes

The increase in Income Tax Expense of $2 million is primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the three months ended March 31, 2006 and 2005 were as follows:

	2006	**2005**
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ -	$ 26
Net Cash Flows From (Used For):		
Operating Activities	45,728	(118,918)
Investing Activities	(57,795)	1,716
Financing Activities	12,067	118,185
Net Increase in Cash and Cash Equivalents	-	983
Cash and Cash Equivalents at End of Period	$ -	$ 1,009

Operating Activities

Our Net Cash Flows From Operating Activities were $46 million in the first three months of 2006. We produced Net income of $4 million during the period and incurred noncash items of $33 million for Depreciation and Amortization and $(19) million for Carrying Costs on Stranded Cost Recovery. 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 decreases in Accounts Payable and Interest Accrued offset in part by a decrease of $121 million in Accounts Receivable. Accounts Payable decreased $53 million primarily due to lower energy related transactions. Interest Accrued decreased $16 million as a result of interest payments on debentures and senior unsecured notes offset by monthly accruals. Cash receipts related to the retail clawback and 2005 storm restoration for nonaffiliated companies as well as fewer energy related receivables reduced outstanding Accounts Receivable by $121 million.

Our Net Cash Flows Used For Operating Activities were $119 million in 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, offset in Accrued Taxes, as noted below. 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 relate to a number of items; the most significant are decreases in Accounts Payable, Accrued Taxes, Net and Accrued Interest offset in part by a decrease in Accounts Receivable, Net. Accounts Payable decreased $25 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 partially offset by monthly accruals.

Investing Activities

Our Net Cash Flows Used For Investing Activities in 2006 were $58 million primarily due to $59 million of Construction Expenditures focused on improved service reliability projects for transmission and distribution systems.

Our Net Cash Flows From Investing Activities in 2005 were $2 million primarily due to a decrease of $32 million in Other Cash Deposits, Net related to principal payments on Securitization Bonds partially offset by Construction Expenditures of $26 million related to projects for improved transmission and distribution service reliability.

For the remainder of 2006, we expect our Construction Expenditures to be approximately $220 million.

Financing Activities

Our Net Cash Flows From Financing Activities in 2006 were $12 million primarily due to the issuance of a $125 million affiliated note with AEP. This increase in Long-term Debt was partially offset by a decrease in Advances from Affiliates, Net of $82 million and the retirement of $31 million of Securitization Bonds.

Our Net Cash Flows From Financing Activities in 2005 were $118 million primarily due to a $238 million increase in Advances from Affiliates, Net and issuances of Pollution Control Bonds of $159 million offset by retirements of Senior Unsecured Notes Payables and Securitization Bonds of $279 million.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2006 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable-Affiliated	$ 125,000	5.14	2007

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Securitization Bonds	$ 30,641	5.01	2010

Liquidity

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

We will use any proceeds received from the securitization (discussed below under Texas Regulatory Activity) to pay down a portion of our equity and debt.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements disclosed above.

Significant Factors

Texas Restructuring

The PUCT issued an order in our True-up Proceeding in February 2006, which determined that our true-up regulatory asset was $1.475 billion, which included carrying costs through September 2005. We filed an application in March 2006 requesting to securitize $1.8 billion of net stranded generation plant costs and related carrying costs to September 1, 2006. The $1.8 billion does not include our other true-up items, which are partially offsetting in nature. These obligations total $491 million and would be payable through a CTC over a period determined by the PUCT. Intervenors and the PUCT staff filed testimony in April 2006. Hearings are scheduled for May. It is possible that the PUCT could reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, a negative impact on the timing of cash flows could result. Cash flows from securitization would be adversely impacted if the PUCT reduces our computation of the amount to be securitized in the securitization proceeding.

The PUCT has not addressed the allocation of stranded costs to our wholesale jurisdiction. We estimate the amount allocated to wholesale to be less than $1 million, while intervenors and PUCT staff filed testimony recommending that $77 million of stranded costs be allocated to our wholesale jurisdiction. We cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that we will not be able to securitize or recover.

Consistent with certain prior securitization determinations, the PUCT may deduct the cost-of-money benefit of accumulated deferred federal income taxes (ADFIT) from the securitization request. Then, the future cost-of-money benefit would be transferred to a separate regulatory asset recoverable in normal delivery rates outside of the securitization process, which would affect the timing of cash recovery. We estimate the total cost-of-money benefit to be $328 million, which we plan to include in our estimated CTC request. Intervenors filed testimony recommending an increase in this amount, along with the retrospective ADFIT amounts, by as much as $175 million.

In addition, the intervenors raised three issues totaling $138 million which were addressed by the PUCT in prior proceedings - the appropriate interest rate for both stranded cost and deferred fuel and the treatment of excess earnings refunds. Other issues raised by the intervenors dealt with the amounts to be securitized versus refunded to customers through the CTC, customer class allocation issues and debt defeasance strategies.

The difference between the recorded securitizable true-up regulatory asset of $1.5 billion at March 31, 2006 and our securitization request of $1.8 billion is detailed in the table below:

		(in millions)
Stranded Generation Plant Costs	$	969
Net Generation-related Regulatory Asset		249
Excess Earnings		(49)
Recorded Net Stranded Generation Plant Costs		1,169
Recorded Debt Carrying Costs on Recorded Net Stranded Generation Plant Costs		284
Recorded Securitizable True-up Regulatory Asset		1,453
Unrecorded But Recoverable Equity Carrying Costs		212
Unrecorded Estimated April 2006 – August 2006 Debt Carrying Costs		40
Unrecorded Securitization Issuance Costs		24
Unrecorded Excess Earnings, Related Return and Other		75
Securitization Request	$	1,804

The principal components of the CTC rate reduction are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to our stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance. We will incur carrying costs on the net negative other true-up regulatory liability balances until fully refunded. We anticipate filing to implement a negative CTC (as a rate reduction) for our net other true-up items in the second quarter of 2006.

The difference between the components of our recorded net regulatory liabilities – other true-up items as of March 31, 2006 and the amount expected to be requested in the CTC proceeding are detailed below:

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		17
Retail Clawback		(61)
Deferred Over-recovered Fuel Balance		(177)
Recorded Net Regulatory Liabilities – Other True-up Items		(160)
ADFIT Benefit		(328)
Unrecorded Carrying Costs and Other		(3)
Estimated CTC Request	$	(491)

If we determine in future securitization and CTC proceedings that it is probable we cannot recover a portion of our recorded net true-up regulatory asset and we are able to estimate the amount of such nonrecovery, we would record a provision for such amount which could have an adverse effect on future results of operations, cash flows and possibly financial condition. We intend to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where we believe the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. We expect that the cities and other intervenors will also pursue vigorously court appeals to further reduce our true-up recoveries. Although we believe we have meritorious arguments, management cannot predict the ultimate outcome of any future proceedings, requested rehearings or court appeals. If the cities and other intervenors succeed in their expected appeals, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Removal from CSW Operating Agreement and SIA

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have already ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters, Note 4 – Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of March 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 536	$ 84	$ 620
Noncurrent Assets	536	5	541
Total MTM Derivative Contract Assets	1,072	89	1,161
Current Liabilities	(455)	(31)	(486)
Noncurrent Liabilities	(316)	(3)	(319)
Total MTM Derivative Contract Liabilities	(771)	(34)	(805)
Total MTM Derivative Contract Net Assets	$ 301	$ 55	$ 356

MTM Risk Management Contract Net Assets Three Months Ended March 31, 2006 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 5,426
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(944)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(7)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	5
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(4,181)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	-
Total MTM Risk Management Contract Net Assets	301
Net Cash Flow Hedge Contracts	55
Total MTM Risk Management Contract Net Assets at March 31, 2006	$ 356

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 68	$ 14	$ 6	$ (1)	$ -	$ -	$ 87
Prices Provided by Other External Sources - OTC Broker Quotes (a)	28	17	44	41	-	-	130
Prices Based on Models and Other Valuation Methods (b)	(26)	28	17	11	34	20	84
Total	$ 70	$ 59	$ 67	$ 51	$ 34	$ 20	$ 301

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (224)
Changes in Fair Value	255
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	7
Ending Balance in AOCI March 31, 2006	$ 38

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $36 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$5	$11	$6	$3	$111	$184	$88	$32

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $79 million and $93 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 123,211	$ 182,147
Sales to AEP Affiliates	1,598	4,964
Other – Nonaffiliated	10,479	14,246
TOTAL	135,288	201,357
EXPENSES		
Fuel and Other Consumables for Electric Generation	1,726	6,098
Purchased Electricity for Resale	1,680	15,370
Other Operation	58,927	80,749
Maintenance	7,789	17,039
Depreciation and Amortization	33,335	29,286
Taxes Other Than Income Taxes	20,363	22,531
TOTAL	123,820	171,073
OPERATING INCOME	11,468	30,284
Other Income (Expense):		
Interest Income	505	1,498
Carrying Costs Income (Expense)	19,423	(5,141)
Allowance for Equity Funds Used During Construction	373	551
Interest Expense	(26,773)	(27,079)
INCOME BEFORE INCOME TAXES	4,996	113
Income Tax Expense (Credit)	1,223	(1,024)
NET INCOME	3,773	1,137
Preferred Stock Dividend Requirements	60	60
EARNINGS APPLICABLE TO COMMON STOCK	$ 3,713	$ 1,077

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

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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 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
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630
Preferred Stock Dividends			(60)		(60)
TOTAL					947,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $141				262	262
NET INCOME			3,773		3,773
TOTAL COMPREHENSIVE INCOME					4,035
MARCH 31, 2006	$ 55,292	$ 132,606	$ 764,597	$ (890)	$ 951,605

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Other Cash Deposits	36,417	66,153
Advances to Affiliates	32,101	-
Accounts Receivable:		
Customers	93,123	209,957
Affiliated Companies	22,304	23,486
Accrued Unbilled Revenues	22,488	25,606
Allowance for Uncollectible Accounts	(376)	(143)
Total Accounts Receivable	137,539	258,906
Unbilled Construction Costs	19,784	19,440
Materials and Supplies	16,237	13,897
Risk Management Assets	620	14,311
Prepayments and Other	2,259	5,231
TOTAL	244,957	377,938
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	827,837	817,351
Distribution	1,506,415	1,476,683
Other	227,411	233,361
Construction Work in Progress	133,785	129,800
Total	2,695,448	2,657,195
Accumulated Depreciation and Amortization	629,538	636,078
TOTAL - NET	2,065,910	2,021,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,698,100	1,688,787
Securitized Transition Assets	582,513	593,401
Long-term Risk Management Assets	541	11,609
Employee Benefits and Pension Assets	114,004	114,733
Deferred Charges and Other	78,200	53,011
TOTAL	2,473,358	2,461,541
Assets Held for Sale – Texas Generation Plants	44,435	44,316
TOTAL ASSETS	$ 4,828,660	$ 4,904,912

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 82,080
Accounts Payable:		
General	67,644	82,666
Affiliated Companies	26,405	65,574
Long-term Debt Due Within One Year – Nonaffiliated	154,383	152,900
Risk Management Liabilities	486	13,024
Accrued Taxes	61,420	54,566
Accrued Interest	16,345	32,497
Other	31,952	45,927
TOTAL	358,635	529,234
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,518,525	1,550,596
Long-term Debt – Affiliated	275,000	150,000
Long-term Risk Management Liabilities	319	7,857
Deferred Income Taxes	1,046,944	1,048,372
Regulatory Liabilities and Deferred Investment Tax Credits	658,887	652,143
Deferred Credits and Other	12,805	13,140
TOTAL	3,512,480	3,422,108
TOTAL LIABILITIES	3,871,115	3,951,342
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Commitments and Contingencies (Note 5)		
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	764,597	760,884
Accumulated Other Comprehensive Income (Loss)	(890)	(1,152)
TOTAL	951,605	947,630
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,828,660	$ 4,904,912

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 3,773	$ 1,137
Adjustments for Noncash Items:		
Depreciation and Amortization	33,335	29,286
Accretion of Asset Retirement Obligations	18	4,529
Deferred Income Taxes	2,928	(5,045)
Carrying Costs on Stranded Cost Recovery	(19,423)	5,141
Mark-to-Market of Risk Management Contracts	5,125	6,879
Over/Under Fuel Recovery	-	2,900
Deferred Property Taxes	(25,755)	(29,820)
Change in Other Noncurrent Assets	(683)	(7,892)
Change in Other Noncurrent Liabilities	1,380	4,898
Changes in Components of Working Capital:		
Accounts Receivable, Net	121,367	39,038
Fuel, Materials and Supplies	(2,569)	98
Accounts Payable	(53,124)	(25,008)
Accrued Taxes, Net	6,854	(117,785)
Customer Deposits	(6,514)	(1,173)
Accrued Interest	(16,152)	(21,638)
Other Current Assets	2,629	(1,879)
Other Current Liabilities	(7,461)	(2,584)
Net Cash Flows From (Used for) Operating Activities	45,728	(118,918)
INVESTING ACTIVITIES		
Construction Expenditures	(58,645)	(26,402)
Change in Other Cash Deposits, Net	29,736	31,541
Change in Advances to Affiliates, Net	(32,101)	-
Purchases of Investment Securities	-	(26,872)
Sales of Investment Securities	-	23,349
Proceeds from Sale of Assets	3,215	-
Other	-	100
Net Cash Flows From (Used For) Investing Activities	(57,795)	1,716
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Affiliated	125,000	-
Issuance of Long-term Debt – Nonaffiliated	-	159,252
Change in Advances from Affiliates, Net	(82,080)	238,486
Retirement of Long-term Debt	(30,641)	(279,386)
Principal Payments for Capital Lease Obligations	(152)	(107)
Dividends Paid on Cumulative Preferred Stock	(60)	(60)
Net Cash From Financing Activities	12,067	118,185
Net Increase in Cash and Cash Equivalents	-	983
Cash and Cash Equivalents at Beginning of Period	-	26
Cash and Cash Equivalents at End of Period	$ -	$ 1,009

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $40,646,000 and $44,721,000 and for income taxes net of refunds was $485,000 and $132,960,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $680,000 and $157,000 in 2006 and 2005, respectively. Noncash construction expenditures included in Accounts Payable of $9,970,000 and $2,970,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to TCC's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 7
Changes in Gross Margin:		
Texas Supply	(3)	
Off-system Sales	1	
Other	(39)	
Total Change in Gross Margin		(41)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	34	
Interest Expense	1	
Total Change in Operating Expenses and Other		35
Income Tax Expense		3
First Quarter of 2006		$ 4

Net Income decreased $3 million in the first quarter of 2006 primarily due to a decrease in Gross Margin of $41 million partially offset by a reduction in Other Operation and Maintenance expenses of $34 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of emissions allowances and purchased power were as follows:

- Texas Supply margins decreased $3 million primarily due to a $7 million decrease in dedicated ERCOT energy sales, offset by an increase of $1 million in provision for refund primarily due to the fuel reconciliation adjustment in 2005 and $3 million of lower fuel and purchased power cost.
- Other revenues decreased $39 million primarily due to a $36 million decrease in revenue resulting from the completion of certain third party construction projects, primarily with the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $34 million primarily due to lower expenses related to the completion of certain third party construction projects, primarily with the Lower Colorado River Authority, of $36 million offset by slightly increased maintenance expenses.

Income Taxes

The decrease in Income Tax Expense of $3 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook, except for Fitch which recently moved us to negative 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 2006.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Removal from CSW Operating Agreement and SIA

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have already ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters, Note 4 – Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Balance Sheet As of March 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 1,109	$ 173	$ 1,282
Noncurrent Assets	1,108	11	1,119
Total MTM Derivative Contract Assets	2,217	184	2,401
Current Liabilities	(855)	(64)	(919)
Noncurrent Liabilities	(653)	(6)	(659)
Total MTM Derivative Contract Liabilities	(1,508)	(70)	(1,578)
Total MTM Derivative Contract Net Assets	$ 709	$ 114	$ 823

MTM Risk Management Contract Net Assets Three Months Ended March 31, 2006 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 2,698
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(395)
Fair Value of New Contracts at Inception When Entered During the Period (a)	4
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(13)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	11
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(1,596)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	-
Total MTM Risk Management Contract Net Assets	709
Net Cash Flow Hedge Contracts	114
Total MTM Risk Management Contract Net Assets at March 31, 2006	$ 823

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 141	$ 29	$ 13	$ (1)	$ -	$ -	$ 182
Prices Provided by Other External Sources - OTC Broker Quotes (a)	58	35	91	85	-	-	269
Prices Based on Models and Other Valuation Methods (b)	30	57	36	22	71	42	258
Total	$ 229	$ 121	$ 140	$ 106	$ 71	$ 42	$ 709

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (111)
Changes in Fair Value	176
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	13
Ending Balance in AOCI March 31, 2006	$ 78

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $74 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$10	$23	$13	$6	$55	$92	$44	$16

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $13 million at both March 31, 2006 and December 31, 2005. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 68,825	$ 71,889
Sales to AEP Affiliates	6,025	11,290
Other	(184)	35,728
TOTAL	74,666	118,907
EXPENSES		
Fuel and Other Consumables for Electric Generation	12,115	12,983
Purchased Electricity for Resale	14,396	16,360
Other Operation	18,556	53,670
Maintenance	5,201	4,219
Depreciation and Amortization	10,223	10,155
Taxes Other Than Income Taxes	5,540	5,705
TOTAL	66,031	103,092
OPERATING INCOME	8,635	15,815
Other Income (Expense):		
Interest Income	219	256
Allowance for Equity Funds Used During Construction	382	73
Interest Expense	(4,362)	(4,984)
INCOME BEFORE INCOME TAXES	4,874	11,160
Income Tax Expense	1,040	3,766
NET INCOME	3,834	7,394
Preferred Stock Dividend Requirements	26	26
Gain on Reacquired Preferred Stock	2	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 3,810	$ 7,368

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

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

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919
Common Stock Dividends			(8,000)		(8,000)
Preferred Stock Dividends			(26)		(26)
Gain on Reacquired Preferred Stock			2		2
TOTAL					305,895
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $102				189	189
NET INCOME			3,834		3,834
TOTAL COMPREHENSIVE INCOME					4,023
MARCH 31, 2006	$ 137,214	$ 2,351	$ 170,668	$ (315)	$ 309,918

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

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Advances to Affiliates	3,046	34,286
Accounts Receivable:		
Customers	55,249	77,678
Affiliated Companies	12,340	26,149
Accrued Unbilled Revenues	4,423	5,016
Allowance for Uncollectible Accounts	(23)	(18)
Total Accounts Receivable	71,989	108,825
Fuel	4,342	2,636
Materials and Supplies	7,308	6,858
Risk Management Assets	1,282	7,114
Prepayments and Other	2,736	5,204
TOTAL	90,703	164,923
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	289,505	288,934
Transmission	294,733	289,029
Distribution	497,005	492,878
Other	161,710	167,849
Construction Work in Progress	51,030	46,424
Total	1,293,983	1,285,114
Accumulated Depreciation and Amortization	477,100	478,519
TOTAL - NET	816,883	806,595
OTHER NONCURRENT ASSETS		
Regulatory Assets	9,432	9,787
Long-term Risk Management Assets	1,119	5,772
Employee Benefits and Pension Assets	45,996	46,289
Deferred Charges and Other	23,067	10,468
TOTAL	79,614	72,316
TOTAL ASSETS	$ 987,200	$ 1,043,834

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

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 28,806	$ 19,739
Affiliated Companies	38,137	84,923
Risk Management Liabilities	919	6,475
Accrued Taxes	25,271	21,212
Other	10,304	21,050
TOTAL	103,437	153,399
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	276,868	276,845
Long-term Risk Management Liabilities	659	3,906
Deferred Income Taxes	131,683	132,335
Regulatory Liabilities and Deferred Investment Tax Credits	141,102	139,732
Deferred Credits and Other	21,184	21,341
TOTAL	571,496	574,159
TOTAL LIABILITIES	674,933	727,558
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,357
Commitments and Contingencies (Note 5)		
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	170,668	174,858
Accumulated Other Comprehensive Income (Loss)	(315)	(504)
TOTAL	309,918	313,919
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 987,200	$ 1,043,834

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

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 3,834	$ 7,394
Adjustments for Noncash Items:		
Depreciation and Amortization	10,223	10,155
Deferred Income Taxes	(1,323)	(1,221)
Mark-to-Market of Risk Management Contracts	1,989	2,973
Over/Under Fuel Recovery	-	1,400
Deferred Property Taxes	(12,360)	(12,218)
Change in Other Noncurrent Assets	(2,003)	(1,705)
Change in Other Noncurrent Liabilities	652	1,613
Changes in Components of Working Capital:		
Accounts Receivable, Net	36,836	24,967
Fuel, Materials and Supplies	(2,156)	(2,704)
Accounts Payable	(36,932)	1,108
Accrued Taxes, Net	4,059	(10,912)
Other Current Assets	1,676	4,361
Other Current Liabilities	(9,775)	(4,368)
Net Cash Flows From (Used For) Operating Activities	(5,280)	20,843
INVESTING ACTIVITIES		
Construction Expenditures	(18,662)	(10,045)
Change in Other Cash Deposits, Net	792	-
Change In Advances to Affiliates, Net	31,240	(1,232)
Proceeds from Sale of Assets	-	250
Net Cash Flows From (Used For) Investing Activities	13,370	(11,027)
FINANCING ACTIVITIES		
Principal Payments for Capital Lease Obligations	(64)	(59)
Dividends Paid on Common Stock	(8,000)	(9,427)
Dividends Paid on Cumulative Preferred Stock	(26)	(26)
Net Cash Flows Used For Financing Activities	(8,090)	(9,512)
Net Increase in Cash and Cash Equivalents	-	304
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ 304

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $6,113,000 and $6,236,000 and for income taxes net of refunds was $0 and $17,447,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $224,000 and $137,000 in 2006 and 2005, respectively. Noncash Construction Expenditures included in Accounts Payable of $2,372,000 and $1,081,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

The condensed notes to TNC's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$	47
Changes in Gross Margin:			
Retail Margins	28		
Transmission Revenues	1		
Other	2		
Total Change in Gross Margin			31
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	13		
Depreciation and Amortization	2		
Taxes Other Than Income Taxes	1		
Carrying Costs Income	6		
Interest Expense	(6)		
Total Change in Operating Expenses and Other			16
Income Tax Expense			(20)
First Quarter of 2006		$	74

Net Income increased by $27 million to $74 million in 2006. The key drivers of the increase were a $31 million net increase in Gross Margin and a $16 million net decrease in Operating Expenses and Other offset by a $20 million increase in Income Tax Expense.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased by $28 million in comparison to 2005 primarily due to a $16 million increase in revenues related to financial transmission rights, net of congestion, and a $10 million increase in retail revenues related to two new industrial customers. The increase in financial transmission rights revenue is due to improved management of price risk related to serving retail load.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased by $13 million primarily due to a decrease of $14 million related to planned outages and a decrease of $5 million in removal costs in comparison to 2005. These decreases were partially offset by a $6 million increase related to the settlement and cancellation of the COLI (corporate owned life insurance) policy in February 2005.
- Carrying Costs Income increased $6 million primarily due to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased $6 million primarily due to recent long-term debt issuances and higher interest rates on replacement debt.

Income Taxes

The increase in Income Tax Expense of $20 million is primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the three months ended March 31, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,741	$ 1,543
Net Cash Flows From (Used For):		
Operating Activities	212,542	80,946
Investing Activities	(196,459)	(165,691)
Financing Activities	(16,372)	85,337
Net Increase (Decrease) in Cash and Cash Equivalents	(289)	592
Cash and Cash Equivalents at End of Period	$ 1,452	$ 2,135

Operating Activities

Our Net Cash Flows From Operating Activities were $213 million in 2006. We produced income of $74 million during the period and 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 current period activity in working capital had two significant items, an increase in Accounts Receivable, Net and Accrued Taxes, Net. During the first quarter of 2006, we did not make any federal income tax payments and collected receivables from our affiliates related to power sales, settled litigation and emission allowances.

Our Net Cash Flows From Operating Activities were $81 million in 2005. We produced income of $47 million during the period and a noncash expense item 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.

Investing Activities

Our Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of $197 million and $130 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades for both periods. In 2006 and 2005, capital projects for transmission expenditures are primarily related to the Wyoming-Jacksons Ferry 765 kV line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on various plants and the flue gas desulfurization (FGD) project at the Amos and Mountaineer Plants. For the remainder of 2006, we expect construction expenditures to be approximately $750 million.

Financing Activities

Our Net Cash Flows Used For Financing Activities were $16 million in 2006. We retired a First Mortgage Bond of $100 million and incurred obligations of $50 million relating to pollution control bonds. We repaid short-term borrowings from the Utility Money Pool of $30 million. In addition, we received funds of $68 million related to a long-term coal purchase contract amended in March 2006. See "Coal Contract Amendment" within "Significant Factors" for additional information.

Our Net Cash Flows From Financing Activities were $85 million in 2005. We issued Senior Unsecured Notes of $200 million and received a capital contribution from our parent of $100 million. In addition, we repaid $211 million of advances from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2006 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$ 50,275	Variable	2036

Retirements

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
First Mortgage Bonds	$ 100,000	6.80	2006
Other Debt	3	13.718	2026

In April 2006, we issued $250 million, 5.55% senior notes due in 2011 and $250 million, 6.375% senior notes due in 2036. The proceeds were used for general corporate purposes including funding our construction program, repaying advances from the Utility Money Pool and replenishing working capital.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed above.

Significant Factors

Coal Contract Amendment

We negotiated an amendment to a nonderivative coal contract that was assigned to a new owner of a coal supplier to which we were contractually obligated. The amended contract includes adjustments in the quantity related to the shortfall of tons in prior years, escalated tonnage deliveries in 2006 and a pricing change related to future coal deliveries. In March 2006, the new owner agreed to pay us $80 million for the settlement, release and amendment of the original contract. With respect to prior years' undelivered coal, the new owner paid us $12 million for the shortfall tons. With respect to deliveries of coal in 2006-2007, the third party paid us the remaining $68 million for the agreed upon price increase.

The receipt of funds reduces the risk that the third party will short future deliveries. However, if they fail to deliver, we are not contractually obligated to repay any portion of the settlement payment. Our net coal price will not materially change from the original contract price as a result of the $68 million payment that we received for future coal deliveries through 2007.

Since there are no further requirements related to the liquidation of the shortfall tons, we recognized the $12 million shortfall payment in the first quarter of 2006. We recorded a $5 million reduction in Regulatory Assets on our Condensed Consolidated Balance Sheet and recorded the remaining $7 million as a reduction to Fuel and Other Consumables for Electric Generation on our Condensed Consolidated Statement of Income. We recorded the $68 million payment within Deferred Credits and Other on our Condensed Consolidated Balance Sheet. To the extent tons are received, payment of the higher contracted price per ton will effectively result in a repayment of funds to the coal supplier.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 101,475	$ 20,235	$ -	$ 121,710
Noncurrent Assets	158,144	755	-	158,899
Total MTM Derivative Contract Assets	259,619	20,990	-	280,609
Current Liabilities	(83,014)	(5,006)	(1,240)	(89,260)
Noncurrent Liabilities	(114,717)	(1,581)	(10,863)	(127,161)
Total MTM Derivative Contract Liabilities	(197,731)	(6,587)	(12,103)	(216,421)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 61,888	$ 14,403	$ (12,103)	$ 64,188

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	56,407
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(3,099)
Fair Value of New Contracts at Inception When Entered During the Period (a)		170
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(1,182)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		448
Changes in Fair Value Due to Market Fluctuations During the Period (b)		2,406
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		6,738
Total MTM Risk Management Contract Net Assets		61,888
Net Cash Flow & Fair Value Hedge Contracts		14,403
DETM Assignment (d)		(12,103)
Total MTM Risk Management Contract Net Assets at March 31, 2006	$	64,188

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 9,768	$ 2,033	$ 903	$ (72)	$ -	$ -	$ 12,632
Prices Provided by Other External Sources – OTC Broker Quotes (a)	7,005	5,987	8,140	6,725	-	-	27,857
Prices Based on Models and Other Valuation Methods (b)	(1,427)	5,761	3,863	3,976	8,515	711	21,399
Total	$ 15,346	$ 13,781	$ 12,906	$ 10,629	$ 8,515	$ 711	$ 61,888

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006

(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (1,480)	$ (171)	$ (14,770)	$ (16,421)
Changes in Fair Value	5,964	-	5,340	11,304
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	899	2	1,063	1,964
Ending Balance in AOCI March 31, 2006	$ 5,383	$ (169)	$ (8,367)	$ (3,153)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,502 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$682	$1,604	$867	$427	$732	$1,216	$579	$209

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $123 million and $142 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 559,993	$ 476,027
Sales to AEP Affiliates	71,772	79,170
Other	2,676	2,498
TOTAL	634,441	557,695
EXPENSES		
Fuel and Other Consumables for Electric Generation	166,853	115,144
Purchased Electricity for Resale	27,616	28,233
Purchased Electricity from AEP Affiliates	122,399	126,963
Other Operation	70,197	73,773
Maintenance	37,839	47,190
Depreciation and Amortization	47,972	49,959
Taxes Other Than Income Taxes	23,092	24,074
TOTAL	495,968	465,336
OPERATING INCOME	138,473	92,359
Other Income (Expense):		
Interest Income	951	562
Carrying Costs Income	6,011	98
Allowance for Equity Funds Used During Construction	2,476	2,211
Interest Expense	(30,268)	(24,199)
INCOME BEFORE INCOME TAXES	117,643	71,031
Income Tax Expense	44,049	24,359
NET INCOME	73,594	46,672
Preferred Stock Dividend Requirements including Capital Stock Expense	238	797
EARNINGS APPLICABLE TO COMMON STOCK	$ 73,356	$ 45,875

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

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701
Common Stock Dividends			(2,500)		(2,500)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		38	(38)		-
TOTAL					1,801,001
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,144				13,268	13,268
NET INCOME			73,594		73,594
TOTAL COMPREHENSIVE INCOME					86,862
MARCH 31, 2006	$ 260,458	$ 924,875	$ 705,872	$ (3,342)	$ 1,887,863

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,452	$ 1,741
Accounts Receivable:		
Customers	171,749	141,810
Affiliated Companies	63,086	153,453
Accrued Unbilled Revenues	34,704	51,201
Miscellaneous	3,908	527
Allowance for Uncollectible Accounts	(3,539)	(1,805)
Total Accounts Receivable	269,908	345,186
Fuel	52,128	64,657
Materials and Supplies	54,468	54,967
Risk Management Assets	121,710	132,247
Accrued Tax Benefits	-	32,979
Margin Deposits	36,888	28,936
Prepayments and Other	32,714	46,193
TOTAL	569,268	706,906
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,818,411	2,798,157
Transmission	1,275,354	1,266,855
Distribution	2,190,230	2,141,153
Other	326,997	323,158
Construction Work in Progress	735,480	647,638
Total	7,346,472	7,176,961
Accumulated Depreciation and Amortization	2,541,697	2,524,855
TOTAL - NET	4,804,775	4,652,106
OTHER NONCURRENT ASSETS		
Regulatory Assets	454,658	457,294
Long-term Risk Management Assets	158,899	176,231
Deferred Charges and Other	262,869	261,556
TOTAL	876,426	895,081
TOTAL ASSETS	$ 6,250,469	$ 6,254,093

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 164,192	$ 194,133
Accounts Payable:		
General	222,271	230,570
Affiliated Companies	65,134	85,941
Long-term Debt Due Within One Year – Nonaffiliated	46,927	146,999
Risk Management Liabilities	89,260	121,165
Customer Deposits	66,324	79,854
Accrued Taxes	73,034	49,833
Accrued Interest	44,125	28,614
Other	60,079	80,132
TOTAL	831,346	1,017,241
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,954,664	1,904,379
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	127,161	147,117
Deferred Income Taxes	948,109	952,497
Regulatory Liabilities and Deferred Investment Tax Credits	206,492	201,230
Deferred Credits and Other	177,050	110,144
TOTAL	3,513,476	3,415,367
TOTAL LIABILITIES	4,344,822	4,432,608
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	924,875	924,837
Retained Earnings	705,872	635,016
Accumulated Other Comprehensive Income (Loss)	(3,342)	(16,610)
TOTAL	1,887,863	1,803,701
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,250,469	$ 6,254,093

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 73,594	$ 46,672
Adjustments for Noncash Items:		
Depreciation and Amortization	47,972	49,959
Deferred Income Taxes	(11,423)	9,445
Carrying Costs Income	(6,011)	(98)
Mark-to-Market of Risk Management Contracts	(5,696)	(13,360)
Pension Contributions to Qualified Plan Trusts	-	(19,937)
Over/Under Fuel Recovery, Net	7,832	3,320
Change in Other Noncurrent Assets	5,878	(19,490)
Change in Other Noncurrent Liabilities	5,848	(414)
Changes in Components of Working Capital:		
Accounts Receivable, Net	75,278	3,113
Fuel, Materials and Supplies	13,028	(5,764)
Accounts Payable	(30,148)	32,411
Accrued Taxes, Net	56,180	(21,316)
Customer Deposits	(13,530)	13,557
Accrued Interest	15,511	16,965
Other Current Assets	(1,718)	(7,918)
Other Current Liabilities	(20,053)	(6,199)
Net Cash Flows From Operating Activities	212,542	80,946
INVESTING ACTIVITIES		
Construction Expenditures	(196,561)	(129,823)
Change in Other Cash Deposits, Net	-	(13,947)
Change in Advances to Affiliates, Net	-	(29,054)
Proceeds from Sales of Assets	102	7,133
Net Cash Flows Used For Investing Activities	(196,459)	(165,691)
FINANCING ACTIVITIES		
Capital Contributions from Parent	-	100,000
Issuance of Long-term Debt – Nonaffiliated	49,677	198,189
Change in Advances from Affiliates, Net	(29,941)	(211,060)
Retirement of Long-term Debt – Nonaffiliated	(100,003)	-
Principal Payments for Capital Lease Obligations	(1,483)	(1,592)
Funds From Amended Coal Contract	68,078	-
Dividends Paid on Common Stock	(2,500)	-
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Net Cash Flows From (Used For) Financing Activities	(16,372)	85,337
Net Increase (Decrease) in Cash and Cash Equivalents	(289)	592
Cash and Cash Equivalents at Beginning of Period	1,741	1,543
Cash and Cash Equivalents at End of Period	$ 1,452	$ 2,135

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $14,686,000 and $5,842,000 and for income taxes net of refunds was $1,771,000 and $38,845,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $1,184,000 and $460,000 in 2006 and 2005, respectively. Noncash Construction Expenditures included in Accounts Payable of $83,682,000 and $46,146,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

The condensed notes to APCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 47
Changes in Gross Margin:		
Retail Margins	24	
Off-system Sales	8	
Transmission Revenues	2	
Other	6	
Total Change in Gross Margin		40
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(15)	
Depreciation and Amortization	(8)	
Taxes Other Than Income Taxes	(3)	
Carrying Costs Income	(2)	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(33)
Income Tax Expense		(3)
First Quarter of 2006		$ 51

Net Income remained relatively flat in the first quarter of 2006 compared to the first quarter of 2005.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins were $24 million higher than the prior period primarily due to Rate Stabilization Plan and Transition Regulatory Asset rate increases effective January 1, 2006 as well as the addition of Monongahela Power Ohio customers on December 31, 2005, partially offset by reduced fuel margins.
- Off-system Sales increased $8 million primarily due to increased AEP Power Pool sales partially offset by lower optimization activity.
- Other revenues increased $6 million primarily due to higher gains on sale of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $15 million due to the 2005 establishment of a regulatory asset for PJM administrative fees, an increase in transmission expenses related to the AEP Transmission Equalization Agreement and favorable adjustments in the prior year quarter related to the corporate owned life insurance policy and storm expense.
- Depreciation and Amortization expense increased $8 million primarily due to increased amortization of regulatory assets and an increase in depreciation expense due to a greater depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power's Ohio assets.
- Taxes Other Than Income Taxes increased $3 million due to increases in real and personal property taxes.
- Interest Expense increased $5 million primarily due to a new long-term debt issuance during the fourth quarter of 2005.

Income Tax

The increase of $3 million in Income Tax Expense is primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2006.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters, Note 4 – Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of March 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 59,753	$ 7,087	$ -	$ 66,840
Noncurrent Assets	93,183	446	-	93,629
Total MTM Derivative Contract Assets	152,936	7,533	-	160,469
Current Liabilities	(48,676)	(2,614)	(733)	(52,023)
Noncurrent Liabilities	(67,300)	(231)	(6,423)	(73,954)
Total MTM Derivative Contract Liabilities	(115,976)	(2,845)	(7,156)	(125,977)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 36,960	$ 4,688	$ (7,156)	$ 34,492

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 33,322
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(3,337)
Fair Value of New Contracts at Inception When Entered During the Period (a)	173
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(665)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	456
Changes in Fair Value Due to Market Fluctuations During the Period (b)	7,022
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(11)
Total MTM Risk Management Contract Net Assets	36,960
Net Cash Flow Hedge Contracts	4,688
DETM Assignment (d)	(7,156)
Total MTM Risk Management Contract Net Assets at March 31, 2006	$ 34,492

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 5,775	$ 1,202	$ 534	$ (42)	$ -	$ -	$ 7,469
Prices Provided by Other External Sources – OTC Broker Quotes (a)	4,260	3,399	4,766	3,976	-	-	16,401
Prices Based on Models and Other Valuation Methods (b)	(820)	3,667	2,438	2,351	5,034	420	13,090
Total	$ 9,215	$ 8,268	$ 7,738	$ 6,285	$ 5,034	$ 420	$ 36,960

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (859)
Changes in Fair Value	3,510
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	531
Ending Balance in AOCI March 31, 2006	$ 3,182

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,043 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$403	$948	$513	$253	$424	$705	$335	$121

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $76 million and $86 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 413,669	$ 328,603
Sales to AEP Affiliates	13,769	34,814
Other	1,330	3,716
TOTAL	428,768	367,133
EXPENSES		
Fuel and Other Consumables for Electric Generation	69,820	66,435
Purchased Electricity for Resale	24,765	9,203
Purchased Electricity from AEP Affiliates	82,477	79,775
Other Operation	55,961	43,229
Maintenance	17,934	15,384
Depreciation and Amortization	45,812	38,198
Taxes Other Than Income Taxes	39,502	36,242
TOTAL	336,271	288,466
OPERATING INCOME	92,497	78,667
Other Income (Expense):		
Interest Income	455	917
Carrying Costs Income	716	2,757
Allowance for Equity Funds Used During Construction	464	279
Interest Expense	(17,520)	(12,912)
INCOME BEFORE INCOME TAXES	76,612	69,708
Income Tax Expense	25,275	22,240
NET INCOME	51,337	47,468
Capital Stock Expense	39	254
EARNINGS APPLICABLE TO COMMON STOCK	$ 51,298	$ 47,214

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

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546
Common Stock Dividends			(22,500)		(22,500)
Capital Stock Expense		39	(39)		-
TOTAL					959,046
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,176				4,041	4,041
NET INCOME			51,337		51,337
TOTAL COMPREHENSIVE INCOME					55,378
MARCH 31, 2006	$ 41,026	$ 580,074	$ 390,163	$ 3,161	$ 1,014,424

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 757	$ 940
Advances to Affiliates	6,867	-
Accounts Receivable:		
Customers	57,283	43,143
Affiliated Companies	22,610	67,694
Accrued Unbilled Revenues	6,080	10,086
Miscellaneous	3,828	2,012
Allowance for Uncollectible Accounts	(1,243)	(1,082)
Total Accounts Receivable	88,558	121,853
Fuel	36,099	28,579
Materials and Supplies	27,430	27,519
Emission Allowances	15,350	20,181
Risk Management Assets	66,840	76,507
Margin Deposits	21,809	16,832
Accrued Tax Benefits	15,417	36,838
Prepayments and Other	8,760	6,714
TOTAL	287,887	335,963
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,883,412	1,874,652
Transmission	468,553	457,937
Distribution	1,411,856	1,380,722
Other	186,223	184,096
Construction Work in Progress	152,937	129,246
Total	4,102,981	4,026,653
Accumulated Depreciation and Amortization	1,539,816	1,500,858
TOTAL - NET	2,563,165	2,525,795
OTHER NONCURRENT ASSETS		
Regulatory Assets	225,936	231,599
Long-term Risk Management Assets	93,629	101,512
Deferred Charges and Other	228,604	237,925
TOTAL	548,169	571,036
TOTAL ASSETS	$ 3,399,221	$ 3,432,794

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 17,609
Accounts Payable:		
General	84,371	59,134
Affiliated Companies	47,503	59,399
Risk Management Liabilities	52,023	69,036
Customer Deposits	39,112	47,013
Accrued Taxes	128,435	157,729
Accrued Interest	14,781	18,908
Other	24,750	31,321
TOTAL	390,975	460,149
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,097,021	1,096,920
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	73,954	84,291
Deferred Income Taxes	504,062	498,232
Regulatory Liabilities and Deferred Investment Tax Credits	171,700	165,344
Deferred Credits and Other	47,085	46,312
TOTAL	1,993,822	1,991,099
TOTAL LIABILITIES	2,384,797	2,451,248
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value Per Share:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,074	580,035
Retained Earnings	390,163	361,365
Accumulated Other Comprehensive Income (Loss)	3,161	(880)
TOTAL	1,014,424	981,546
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,399,221	$ 3,432,794

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 51,337	$ 47,468
Adjustments for Noncash Items:		
Depreciation and Amortization	45,812	38,198
Deferred Income Taxes	3,816	(2,613)
Carrying Costs Income	(716)	(2,757)
Mark-to-Market of Risk Management Contracts	(3,624)	(5,120)
Pension Contributions to Qualified Plan Trusts	-	(12,611)
Deferred Property Taxes	10,884	15,938
Change in Other Noncurrent Assets	(11,084)	(18,027)
Change in Other Noncurrent Liabilities	5,800	171
Changes in Components of Working Capital:		
Accounts Receivable, Net	33,295	14,059
Fuel, Materials and Supplies	(7,431)	7,529
Accounts Payable	12,540	(18,636)
Accrued Taxes, Net	(7,873)	(61,908)
Customer Deposits	(7,901)	6,173
Accrued Interest	(4,127)	(8,271)
Other Current Assets	(728)	(3,926)
Other Current Liabilities	(6,571)	(8,031)
Net Cash Flows From (Used For) Operating Activities	113,429	(12,364)
INVESTING ACTIVITIES		
Construction Expenditures	(65,032)	(36,227)
Change in Other Cash Deposits, Net	(1,151)	(7,125)
Change in Advances to Affiliates, Net	(6,867)	82,134
Proceeds from Sale of Assets	306	3,663
Net Cash Flows From (Used For) Investing Activities	(72,744)	42,445
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(17,609)	-
Principal Payments for Capital Lease Obligations	(759)	(935)
Dividends Paid on Common Stock	(22,500)	(28,500)
Net Cash Flows Used For Financing Activities	(40,868)	(29,435)
Net Increase (Decrease) in Cash and Cash Equivalents	(183)	646
Cash and Cash Equivalents at Beginning of Period	940	58
Cash and Cash Equivalents at End of Period	$ 757	$ 704

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $22,320,000 and $21,898,000 and for income taxes net of refunds was $2,533,000 and $57,037,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions in 2006 and 2005 were $1,102,000 and $160,000, respectively. Noncash construction expenditures included in Accounts Payable of $12,054,000 and $2,771,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

First Quarter of 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 40
Changes in Gross Margin:		
Retail Margins	6	
Off-System Sales (a)	16	
Transmission Revenues	2	
Other	12	
Total Change in Gross Margin		36
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Depreciation and Amortization	(1)	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		(11)
First Quarter of 2006		$ 58

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $18 million to $58 million in 2006. The key drivers of the increase were a $36 million increase in Gross Margin partially offset by an $11 million increase in Income Tax Expense.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $6 million primarily due to increases in industrial sales and capacity settlement revenues of $3 million under the Interconnection Agreement.
- Off-system Sales increased $16 million primarily due to the addition of new municipal contracts including new rates and increased demand beginning January 2006.
- Other revenues increased $12 million primarily due to increased River Transportation Division (RTD) revenues for barging coal to affiliated companies' plants and gains on sales of emission allowances. Related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in our earning only an approved return.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily due to higher expenses for RTD and the gain for settlement and cancellation of the corporate owned life insurance policies in February 2005 partially offset by a reduction in distribution maintenance expense. Prior year distribution maintenance expense for overhead power lines included the costs of the January 2005 ice storm.

Income Taxes

Income Tax Expense increased $11 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

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

Cash Flow

Cash flows for the three months ended March 31, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 854	$ 511
Net Cash Flows From (Used For):		
Operating Activities	195,328	70,893
Investing Activities	(139,649)	(82,849)
Financing Activities	(55,924)	12,019
Net Increase (Decrease) in Cash and Cash Equivalents	(245)	63
Cash and Cash Equivalents at End of Period	$ 609	$ 574

Operating Activities

Our Net Cash Flows From Operating Activities were $195 million in 2006. We produced Net Income of $58 million during the period and a noncash expense item of $44 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant relates to Accrued Taxes, Net and Accounts Receivable, Net. During the first quarter of 2006, we did not make any federal income tax payments and collected receivables from our affiliates related to power sales, settled litigation and emission allowances.

Our Net Cash Flows From Operating Activities were $71 million in 2005. We produced Net Income of $40 million during the period and a noncash expense item of $43 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 relates to a number of items; the most significant relates to a $46 million change in Accrued Taxes, Net reflecting taxes paid during 2005.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of $89 million and $52 million and acquisition of nuclear fuel of $34 million and $21 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. We also invested in capital projects to improve air quality and water intake systems. For the remainder of 2006, we expect our Construction Expenditures to be approximately $222 million.

Financing Activities

Our Net Cash Flows Used For Financing Activities were $56 million in 2006. We used cash from operations to repay Advances from Affiliates and pay common dividends.

Our cash flows from financing activities were $12 million in 2005. Advances from Affiliates funded our construction expenditures.

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2006.

Liquidity

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

<u>Off-Balance Sheet Arrangements</u>

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only 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 including the lease of Rockport Plant Unit 2 see "Off-balance Sheet Arrangements" in the "Management's Financial Discussion and Analysis" section of our 2005 Annual Report.

<u>Summary Obligation Information</u>

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

<u>Significant Factors</u>

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

<u>Critical Accounting Estimates</u>

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our Condensed Consolidated Balance Sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 60,866	$ 7,239	$ -	$ 68,105
Noncurrent Assets	94,960	456	-	95,416
Total MTM Derivative Contract Assets	155,826	7,695	-	163,521
Current Liabilities	(49,439)	(3,264)	(749)	(53,452)
Noncurrent Liabilities	(68,380)	(237)	(6,560)	(75,177)
Total MTM Derivative Contract Liabilities	(117,819)	(3,501)	(7,309)	(128,629)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 38,007	$ 4,194	$ (7,309)	$ 34,892

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	33,932
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		977
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(655)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(2,054)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		5,807
Total MTM Risk Management Contract Net Assets		38,007
Net Cash Flow & Fair Value Hedge Contracts		4,194
DETM Assignment (d)		(7,309)
Total MTM Risk Management Contract Net Assets at March 31, 2006	$	34,892

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in our Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 5,899	$ 1,228	$ 545	$ (43)	$ -	$ -	$ 7,629
Prices Provided by Other External Sources – OTC Broker Quotes (a)	4,433	3,374	4,836	4,061	-	-	16,704
Prices Based on Models and Other Valuation Methods (b)	(819)	3,926	2,595	2,401	5,142	429	13,674
Total	$ 9,513	$ 8,528	$ 7,976	$ 6,419	$ 5,142	$ 429	$ 38,007

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (877)	$ (2,590)	$ (3,467)
Changes in Fair Value	3,585	-	3,585
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	542	80	622
Ending Balance in AOCI March 31, 2006	$ 3,250	$ (2,510)	$ 740

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,786 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$412	$968	$524	$258	$433	$720	$343	$124

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $49 million and $55 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 403,769	$ 348,353
Sales to AEP Affiliates	88,534	92,538
Other – Affiliated	15,094	10,339
Other – Nonaffiliated	8,382	6,329
TOTAL	515,779	457,559
EXPENSES		
Fuel and Other Consumables for Electric Generation	89,452	79,237
Purchased Electricity for Resale	11,010	11,272
Purchased Electricity from AEP Affiliates	86,422	74,009
Other Operation	117,206	104,402
Maintenance	45,219	54,322
Depreciation and Amortization	44,126	42,745
Taxes Other Than Income Taxes	18,906	18,682
TOTAL	412,341	384,669
OPERATING INCOME	103,438	72,890
Other Income (Expense):		
Interest Income	694	433
Allowance for Equity Funds Used During Construction	1,924	1,649
Interest Expense	(17,533)	(15,606)
INCOME BEFORE INCOME TAXES	88,523	59,366
Income Tax Expense	30,645	19,697
NET INCOME	57,878	39,669
Preferred Stock Dividend Requirements including Capital Stock Expense	85	118
EARNINGS APPLICABLE TO COMMON STOCK	$ 57,793	$ 39,551

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

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(85)		(85)
TOTAL					1,210,007
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,265				4,207	4,207
NET INCOME			57,878		57,878
TOTAL COMPREHENSIVE INCOME					62,085
MARCH 31, 2006	$ 56,584	$ 861,290	$ 353,580	$ 638	$ 1,272,092

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 609	$ 854
Accounts Receivable:		
Customers	68,193	62,614
Affiliated Companies	79,243	127,981
Miscellaneous	2,131	1,982
Allowance for Uncollectible Accounts	(907)	(898)
Total Accounts Receivable	148,660	191,679
Fuel	29,747	25,894
Materials and Supplies	121,380	118,039
Risk Management Assets	68,105	78,134
Accrued Tax Benefits	26,000	51,846
Margin Deposits	22,276	17,115
Prepayments and Other	8,602	14,188
TOTAL	425,379	497,749
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,146,481	3,128,078
Transmission	1,031,154	1,028,496
Distribution	1,053,772	1,029,498
Other (including nuclear fuel and coal mining)	463,346	465,130
Construction Work in Progress	332,470	311,080
Total	6,027,223	5,962,282
Accumulated Depreciation, Depletion and Amortization	2,850,675	2,822,558
TOTAL - NET	3,176,548	3,139,724
OTHER NONCURRENT ASSETS		
Regulatory Assets	215,523	222,686
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,160,089	1,133,567
Long-term Risk Management Assets	95,416	103,645
Deferred Charges and Other	171,164	164,938
TOTAL	1,642,192	1,624,836
TOTAL ASSETS	$ 5,244,119	$ 5,262,309

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 49,137	$ 93,702
Accounts Payable:		
General	117,455	139,334
Affiliated Companies	40,241	60,324
Long-term Debt Due Within One Year	364,406	364,469
Risk Management Liabilities	53,452	71,032
Customer Deposits	41,227	49,258
Accrued Taxes	73,592	56,567
Other	110,506	112,839
TOTAL	850,016	947,525
NONCURRENT LIABILITIES		
Long-term Debt	1,083,098	1,080,471
Long-term Risk Management Liabilities	75,177	86,159
Deferred Income Taxes	340,347	335,264
Regulatory Liabilities and Deferred Investment Tax Credits	729,080	710,015
Asset Retirement Obligations	749,858	737,959
Deferred Credits and Other	136,367	136,740
TOTAL	3,113,927	3,086,608
TOTAL LIABILITIES	3,963,943	4,034,133
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,290	861,290
Retained Earnings	353,580	305,787
Accumulated Other Comprehensive Income (Loss)	638	(3,569)
TOTAL	1,272,092	1,220,092
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,244,119	$ 5,262,309

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 57,878	$ 39,669
Adjustments for Noncash Items:		
Depreciation and Amortization	44,126	42,745
Accretion of Asset Retirement Obligations	11,907	11,664
Deferred Income Taxes	3,493	(876)
Deferred Investment Tax Credits	(1,820)	(1,832)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(1,639)	5,517
Amortization of Nuclear Fuel	13,596	14,394
Mark-to-Market of Risk Management Contracts	(4,060)	(5,722)
Pension Contributions to Qualified Plan Trusts	-	(15,350)
Deferred Property Taxes	(9,839)	(9,089)
Change in Other Noncurrent Assets	11,184	4,699
Change in Other Noncurrent Liabilities	8,752	2,830
Changes in Components of Working Capital:		
Accounts Receivable, Net	43,019	23,265
Fuel, Materials and Supplies	(7,194)	4,455
Accounts Payable	(7,010)	(12,771)
Accrued Taxes, Net	42,871	(46,291)
Accrued Interest	11,623	9,607
Customer Deposits	(8,031)	4,751
Accrued Rent – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	428	(5,072)
Other Current Liabilities	(32,420)	(14,164)
Net Cash Flows From Operating Activities	195,328	70,893
INVESTING ACTIVITIES		
Construction Expenditures	(89,411)	(52,456)
Change in Advances to Affiliates, Net	-	5,093
Changes in Other Cash Deposits, Net	(3)	(7,966)
Purchases of Investment Securities	(150,239)	(151,980)
Sales of Investment Securities	134,258	136,743
Acquisitions of Nuclear Fuel	(34,427)	(21,444)
Proceeds from Sales of Assets	173	9,161
Net Cash Flows Used For Investing Activities	(139,649)	(82,849)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(44,565)	95,967
Retirement of Cumulative Preferred Stock	-	(61,445)
Principal Payments for Capital Lease Obligations	(1,274)	(1,418)
Dividends Paid on Common Stock	(10,000)	(21,000)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Net Cash Flows From (Used For) Financing Activities	(55,924)	12,019
Net Increase (Decrease) in Cash and Cash Equivalents	(245)	63
Cash and Cash Equivalents at Beginning of Period	854	511
Cash and Cash Equivalents at End of Period	$ 609	$ 574

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $4,776,000 and $5,035,000 and for income taxes net of refunds was $1,324,000 and $82,338,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $2,218,000 and $404,000 in 2006 and 2005, respectively. Noncash construction expenditures included in Accounts Payable of $27,624,000 and $16,823,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

The condensed notes to I&M's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 10
Changes in Gross Margin:		
Retail Margins	(4)	
Off-system Sales	1	
Other	6	
Total Change in Gross Margin		3
Other Operation and Maintenance		(1)
Income Tax Expense		(2)
First Quarter of 2006		$ 10

Net Income was unchanged in comparison to 2005.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins decreased by $4 million in comparison to 2005 primarily due to increased capacity settlement payments.
- Other revenues increased $6 million due primarily to a $3 million adjustment of the Demand Side Management Program regulatory asset in March 2005 and current period gains on the sale of emission allowances.

Income Taxes

The increase in Income Tax Expense of $2 million is primarily due to an increase in pretax book income and state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

Financing Activities

There were no long-term debt issuances or retirements during the first three months of 2006.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Condensed Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 24,318	$ 2,874	$ -	$ 27,192
Noncurrent Assets	37,902	181	-	38,083
Total MTM Derivative Contract Assets	62,220	3,055	-	65,275
Current Liabilities	(19,880)	(1,687)	(297)	(21,864)
Noncurrent Liabilities	(27,474)	(473)	(2,605)	(30,552)
Total MTM Derivative Contract Liabilities	(47,354)	(2,160)	(2,902)	(52,416)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 14,866	$ 895	$ (2,902)	$ 12,859

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	13,518
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		457
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(281)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(918)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		2,090
Total MTM Risk Management Contract Net Assets		14,866
Net Cash Flow & Fair Value Hedge Contracts		895
DETM Assignment (d)		(2,902)
Total MTM Risk Management Contract Net Assets at March 31, 2006	$	12,859

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 2,342	$ 487	$ 217	$ (17)	$ -	$ -	$ 3,029
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1,688	1,426	1,949	1,612	-	-	6,675
Prices Based on Models and Other Valuation Methods (b)	(340)	1,399	937	954	2,042	170	5,162
Total	$ 3,690	$ 3,312	$ 3,103	$ 2,549	$ 2,042	$ 170	$ 14,866

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (352)	$ 158	$ (194)
Changes in Fair Value	1,427	-	1,427
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	216	(22)	194
Ending Balance in AOCI March 31, 2006	$ 1,291	$ 136	$ 1,427

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,320 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$164	$385	$208	$102	$174	$289	$138	$50

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $11 million and $13 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 137,620	$ 109,081
Sales to AEP Affiliates	13,968	18,548
Other	259	431
TOTAL	151,847	128,060
EXPENSES		
Fuel and Other Consumables for Electric Generation	43,966	28,679
Purchased Electricity for Resale	973	2,124
Purchased Electricity from AEP Affiliates	49,526	42,739
Other Operation	13,748	13,942
Maintenance	7,141	5,916
Depreciation and Amortization	11,457	11,152
Taxes Other Than Income Taxes	2,512	2,425
TOTAL	129,323	106,977
OPERATING INCOME	22,524	21,083
Other Income (Expense):		
Interest Income	166	140
Allowance for Equity Funds Used During Construction	101	92
Interest Expense	(7,296)	(7,370)
INCOME BEFORE INCOME TAXES	15,495	13,945
Income Tax Expense	5,665	4,060
NET INCOME	$ 9,830	$ 9,885

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 50,450	$ 208,750	$ 88,864	$ (223)	$ 347,841
Common Stock Dividends			(2,500)		(2,500)
TOTAL					345,341
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $873				1,621	1,621
NET INCOME			9,830		9,830
TOTAL COMPREHENSIVE INCOME					11,451
MARCH 31, 2006	$ 50,450	$ 208,750	$ 96,194	$ 1,398	$ 356,792

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 423	$ 526
Advances to Affiliates	5,923	-
Accounts Receivable:		
Customers	28,183	26,533
Affiliated Companies	7,287	23,525
Accrued Unbilled Revenues	4,393	6,311
Miscellaneous	455	35
Allowance for Uncollectible Accounts	(210)	(147)
Total Accounts Receivable	40,108	56,257
Fuel	11,892	8,490
Materials and Supplies	9,587	10,181
Risk Management Assets	27,192	31,437
Margin Deposits	8,845	6,895
Accrued Tax Benefits	3,920	6,598
Prepayments and Other	2,305	6,324
TOTAL	110,195	126,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	473,778	472,575
Transmission	388,292	386,945
Distribution	462,999	456,063
Other	60,989	63,382
Construction Work in Progress	35,289	35,461
Total	1,421,347	1,414,426
Accumulated Depreciation and Amortization	427,358	425,817
TOTAL - NET	993,989	988,609
OTHER NONCURRENT ASSETS		
Regulatory Assets	115,885	117,432
Long-term Risk Management Assets	38,083	41,810
Deferred Charges and Other	43,055	45,467
TOTAL	197,023	204,709
TOTAL ASSETS	$ 1,301,207	$ 1,320,026

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 6,040
Accounts Payable:		
General	32,895	32,454
Affiliated Companies	19,199	29,326
Long-term Debt Due Within One Year – Affiliated	39,374	39,771
Risk Management Liabilities	21,864	28,770
Customer Deposits	18,516	21,643
Accrued Taxes	8,803	8,805
Accrued Interest	9,361	7,428
Other	10,683	14,096
TOTAL	160,695	188,333
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	427,435	427,219
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	30,552	35,302
Deferred Income Taxes	238,993	234,719
Regulatory Liabilities and Deferred Investment Tax Credits	56,852	56,794
Deferred Credits and Other	9,888	9,818
TOTAL	783,720	783,852
TOTAL LIABILITIES	944,415	972,185
Commitments and Contingencies (Note 5)		
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	96,194	88,864
Accumulated Other Comprehensive Income (Loss)	1,398	(223)
TOTAL	356,792	347,841
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,301,207	$ 1,320,026

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 9,830	$ 9,885
Adjustments for Noncash Items:		
Depreciation and Amortization	11,457	11,152
Deferred Income Taxes	2,217	988
Mark-to-Market of Risk Management Contracts	(1,378)	(3,290)
Pension Contributions to Qualified Plan Trusts	-	(3,045)
Change in Other Noncurrent Assets	2,650	1,722
Change in Other Noncurrent Liabilities	1,845	4,533
Changes in Components of Working Capital:		
Accounts Receivable, Net	16,149	(1,133)
Fuel, Materials and Supplies	(2,808)	(873)
Accounts Payable	(6,212)	1,717
Accrued Taxes, Net	2,676	2,415
Customer Deposits	(3,127)	3,400
Accrued Interest	1,933	2,238
Over/Under Fuel Recovery, Net	2,682	(5,203)
Other Current Assets	(613)	(2,234)
Other Current Liabilities	(3,413)	(833)
Net Cash Flows From Operating Activities	33,888	21,439
INVESTING ACTIVITIES		
Construction Expenditures	(19,376)	(8,987)
Change in Other Cash Deposits, Net	-	(3,314)
Change in Advances to Affiliates, Net	(5,923)	(8,607)
Proceeds from Sale of Assets	191	-
Net Cash Flows Used For Investing Activities	(25,108)	(20,908)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(6,040)	-
Principal Payments for Capital Lease Obligations	(343)	(382)
Dividends Paid on Common Stock	(2,500)	-
Net Cash Flows Used For Financing Activities	(8,883)	(382)
Net Increase (Decrease) in Cash and Cash Equivalents	(103)	149
Cash and Cash Equivalents at Beginning of Period	526	132
Cash and Cash Equivalents at End of Period	$ 423	$ 281

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $4,156,000 and $3,570,000 and for income taxes net of refunds was $214,000 and $691,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $224,000 and $126,000 in 2006 and 2005, respectively. Noncash Construction Expenditures included in Accounts Payable of $3,079,000 and $1,289,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

The condensed notes to KPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income
(in millions)

First Quarter of 2005		$ 99
Changes in Gross Margin:		
Retail Margins	25	
Off-system Sales	(3)	
Transmission Revenues	2	
Other	9	
Total Change in Gross Margin		33
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(23)	
Depreciation and Amortization	(5)	
Carrying Costs Income	(18)	
Interest Expense	3	
Total Change in Operating Expenses and Other		(43)
Income Tax Expense		6
First Quarter of 2006		$ 95

Net Income remained relatively flat in the first quarter of 2006 compared to the first quarter of 2005.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins were $25 million higher than the prior period primarily due to the Rate Stabilization Plan rate increase effective January 1, 2006 and a favorable variance from the receipt of SO_2 allowances from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement, partially offset by decreased capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak load.
- Other revenues increased $9 million primarily due to higher gains on sale of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $23 million primarily due to a planned outage at the Gavin Plant and the establishment of a regulatory asset for PJM administrative fees which reduced expenses in the prior year quarter partially offset by major ice storm expense in the same period.
- Depreciation and Amortization expense increased $5 million due to increased amortization of regulatory assets and an increase in depreciation expense due to a greater depreciable base in electric utility plants.
- Carrying Costs Income decreased $18 million primarily due to the completion of deferrals on the environmental carrying costs from 2004 and 2005 that are being recovered during 2006 through 2008 according to the Rate Stabilization Plan. We recorded $16 million in environmental carrying costs in the first quarter of 2005 related to 2004.

Income Taxes

The decrease of $6 million in Income Tax Expense is primarily due to a decrease in pretax book income and state income taxes, offset in part by changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the three months ended March 31, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,240	$ 9,337
Net Cash Flows From (Used For):		
Operating Activities	184,391	41,223
Investing Activities	(224,251)	(24,025)
Financing Activities	39,577	(25,418)
Net Decrease in Cash and Cash Equivalents	(283)	(8,220)
Cash and Cash Equivalents at End of Period	$ 957	$ 1,117

Operating Activities

Our Net Cash Flows From Operating Activities were $184 million in 2006. We produced income of $95 million during the period and a noncash expense item of $79 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 two items, Accounts Receivable, Net and Accounts Payable. Accounts Receivable, Net decreased $102 million due to collected receivables from our affiliates related to power sales, settled litigation and emission allowances. Accounts Payable decreased $60 million due to emission allowance payments in January 2006 and temporary timing differences for payments to affiliates.

Our Net Cash Flows From Operating Activities were $41 million in 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 Accrued Taxes, Net due to a 2004 federal income tax payment made in the first quarter of 2005.

Investing Activities

Our Net Cash Flows Used For Investing Activities for the first three months of 2006 and 2005 were $224 million and $24 million, respectively, primarily due to Construction Expenditures for environmental upgrades, as well as projects to improve service reliability for transmission and distribution. In 2005, Construction Expenditures of $106 million were offset by a decrease in Advances to Affiliates, Net. For the remainder of 2006, we expect our Construction Expenditures to be approximately $850 million.

Financing Activities

Our Net Cash Flows From Financing Activities during the first three months of 2006 were $40 million due to a $35 million capital contribution from AEP.

Our Net Cash Flows Used For Financing Activities during the first three months of 2005 were $25 million related to a refinancing and payment of dividends.

Financing Activity

Long-term debt issuances and retirements during the first three months of 2006 were:

Issuances

None

Retirements and Principal Payments

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable	$ 1,463	6.81	2008
Notes Payable	3,250	6.27	2009

In April 2006, we issued $65 million variable rate pollution control bonds due in 2036. The proceeds will be used to finance the cost of solid waste disposal facilities at the Mitchell Generating Station.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end, other than the debt issuances, retirements and principal payments discussed above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters, Note 4 – Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 79,205	$ 12,434	$ -	$ 91,639
Noncurrent Assets	121,959	575	-	122,534
Total MTM Derivative Contract Assets	201,164	13,009	-	214,173
Current Liabilities	(67,418)	(4,008)	(944)	(72,370)
Noncurrent Liabilities	(89,828)	(298)	(8,274)	(98,400)
Total MTM Derivative Contract Liabilities	(157,246)	(4,306)	(9,218)	(170,770)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 43,918	$ 8,703	$ (9,218)	$ 43,403

(a) See "Natural Gas Contracts with DETM" section of Note 17 in the 2005 Annual Report.

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	40,894
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(1,742)
Fair Value of New Contracts at Inception When Entered During the Period (a)		223
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(1,060)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		587
Changes in Fair Value Due to Market Fluctuations During the Period (b)		5,037
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(21)
Total MTM Risk Management Contract Net Assets		43,918
Net Cash Flow Hedge Contracts		8,703
DETM Assignment (d)		(9,218)
Total MTM Risk Management Contract Net Assets at March 31, 2006	$	43,403

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 7,439	$ 1,548	$ 688	$ (55)	$ -	$ -	$ 9,620
Prices Provided by Other External Sources – OTC Broker Quotes (a)	3,302	5,245	6,416	5,122	-	-	20,085
Prices Based on Models and Other Valuation Methods (b)	(1,241)	3,173	2,227	3,028	6,485	541	14,213
Total	$ 9,500	$ 9,966	$ 9,331	$ 8,095	$ 6,485	$ 541	$ 43,918

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

We employ the use of interest rate derivative transactions to manage interest rate risk related to existing variable 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 following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (392)	$ (344)	$ 1,491	$ 755
Changes in Fair Value	4,564	-	1,833	6,397
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(89)	3	(135)	(221)
Ending Balance in AOCI March 31, 2006	$ 4,083	$ (341)	$ 3,189	$ 6,931

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $4,581 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$520	$1,221	$660	$325	$583	$968	$461	$166

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $95 million and $111 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 544,639	$ 471,010
Sales to AEP Affiliates	149,259	173,726
Other - Affiliated	3,709	3,454
Other - Nonaffiliated	4,999	6,964
TOTAL	702,606	655,154
EXPENSES		
Fuel and Other Consumables for Electric Generation	235,130	227,049
Purchased Electricity for Resale	21,714	18,762
Purchased Electricity from AEP Affiliates	28,572	25,618
Other Operation	86,637	64,570
Maintenance	47,524	46,475
Depreciation and Amortization	78,813	73,947
Taxes Other Than Income Taxes	47,153	47,299
TOTAL	545,543	503,720
OPERATING INCOME	157,063	151,434
Other Income (Expense):		
Interest Income	637	887
Carrying Costs Income	3,383	22,037
Allowance for Equity Funds Used During Construction	738	427
Interest Expense	(23,414)	(26,163)
INCOME BEFORE INCOME TAXES	138,407	148,622
Income Tax Expense	43,375	49,139
NET INCOME	95,032	99,483
Preferred Stock Dividend Requirements	183	183
EARNINGS APPLICABLE TO COMMON STOCK	$ 94,849	$ 99,300

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

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

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 321,201	$ 466,637	$ 979,354	$ 755	$ 1,767,947
Capital Contribution From Parent		35,000			35,000
Preferred Stock Dividends			(183)		(183)
TOTAL					1,802,764
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,326				6,176	6,176
NET INCOME			95,032		95,032
TOTAL COMPREHENSIVE INCOME					101,208
MARCH 31, 2006	$ 321,201	$ 501,637	$ 1,074,203	$ 6,931	$ 1,903,972

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

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 957	$ 1,240
Accounts Receivable:		
Customers	119,430	125,404
Affiliated Companies	76,327	167,579
Accrued Unbilled Revenues	21,640	14,817
Miscellaneous	5,134	15,644
Allowance for Uncollectible Accounts	(2,470)	(1,517)
Total Accounts Receivable	220,061	321,927
Fuel	114,508	97,600
Materials and Supplies	62,267	60,937
Emission Allowances	30,679	39,251
Risk Management Assets	91,639	115,020
Accrued Tax Benefits	-	39,965
Margin Deposits	28,594	23,053
Prepayments and Other	9,807	4,386
TOTAL	558,512	703,379
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,284,994	4,278,553
Transmission	1,000,501	1,002,255
Distribution	1,271,554	1,258,518
Other	293,835	293,794
Construction Work in Progress	876,384	690,168
Total	7,727,268	7,523,288
Accumulated Depreciation and Amortization	2,772,156	2,738,899
TOTAL - NET	4,955,112	4,784,389
OTHER NONCURRENT ASSETS		
Regulatory Assets	377,447	398,007
Long-term Risk Management Assets	122,534	144,015
Deferred Charges and Other	283,348	300,880
TOTAL	783,329	842,902
TOTAL ASSETS	$ 6,296,953	$ 6,330,670

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

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 81,043	$ 70,071
Accounts Payable:		
General	207,220	210,752
Affiliated Companies	97,767	147,470
Short-term Debt – Nonaffiliated	11,002	10,366
Long-term Debt Due Within One Year – Affiliated	200,000	200,000
Long-term Debt Due Within One Year – Nonaffiliated	12,354	12,354
Risk Management Liabilities	72,370	108,797
Customer Deposits	38,712	51,209
Accrued Taxes	121,925	158,774
Accrued Interest	25,300	36,298
Other	87,284	111,480
TOTAL	954,977	1,117,571
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,782,749	1,787,316
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	98,400	119,247
Deferred Income Taxes	995,059	987,386
Regulatory Liabilities and Deferred Investment Tax Credits	177,394	168,492
Deferred Credits and Other	149,853	154,770
TOTAL	3,403,455	3,417,211
TOTAL LIABILITIES	4,358,432	4,534,782
Minority Interest	17,910	11,302
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,639	16,639
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value Per Share:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	501,637	466,637
Retained Earnings	1,074,203	979,354
Accumulated Other Comprehensive Income (Loss)	6,931	755
TOTAL	1,903,972	1,767,947
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,296,953	$ 6,330,670

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

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 95,032	$ 99,483
Adjustments for Noncash Items:		
Depreciation and Amortization	78,813	73,947
Deferred Income Taxes	3,604	4,092
Carrying Costs Income	(3,383)	(22,037)
Mark-to-Market of Risk Management Contracts	(3,616)	(2,477)
Pension Contributions to Qualified Plan Trusts	-	(20,007)
Deferred Property Taxes	17,331	15,658
Change in Other Noncurrent Assets	4,852	(19,261)
Change in Other Noncurrent Liabilities	13,855	20,969
Changes in Components of Working Capital:		
Accounts Receivable, Net	101,866	(25,474)
Fuel, Materials and Supplies	(18,238)	(483)
Accounts Payable	(60,411)	(38,830)
Accrued Taxes, Net	3,116	(73,250)
Customer Deposits	(12,497)	8,371
Interest Accrued	(10,998)	(16,209)
Other Current Assets	(739)	40,237
Other Current Liabilities	(24,196)	(3,506)
Net Cash Flows From Operating Activities	184,391	41,223
INVESTING ACTIVITIES		
Construction Expenditures	(222,600)	(105,707)
Change in Other Cash Deposits, Net	(1,651)	(9,952)
Change in Advances to Affiliates, Net	-	84,564
Proceeds from Sale of Assets	-	7,070
Net Cash Flows Used For Investing Activities	(224,251)	(24,025)
FINANCING ACTIVITIES		
Capital Contributions from Parent Company	35,000	-
Issuance of Long-term Debt – Nonaffiliated	-	216,798
Change in Short-term Debt, Net – Nonaffiliated	636	(4,796)
Change in Advances from Affiliates, Net	10,972	-
Retirement of Long-term Debt – Nonaffiliated	(4,713)	(222,713)
Retirement of Cumulative Preferred Stock	-	(5,000)
Principal Payments for Capital Lease Obligations	(2,135)	(2,024)
Dividends Paid on Common Stock	-	(7,500)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Net Cash Flows From (Used For) Financing Activities	39,577	(25,418)
Net Decrease in Cash and Cash Equivalents	(283)	(8,220)
Cash and Cash Equivalents at Beginning of Period	1,240	9,337
Cash and Cash Equivalents at End of Period	$ 957	$ 1,117

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $29,152,000 and $37,519,000 and for income taxes net of refunds was $922,000 and $87,763,000 in 2006 and 2005, respectively. Noncash acquisitions under capital leases were $927,000 and $555,000 in 2006 and 2005, respectively. Noncash construction expenditures included in Accounts Payable of $82,024,000 and $64,611,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

The condensed notes to OPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. 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 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income (Loss)
(in millions)

First Quarter of 2005		$ 1
Changes in Gross Margin:		
Retail and Off-system Sales Margins	3	
Transmission Revenues	1	
Other	2	
Total Change in Gross Margin		6
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(15)	
Depreciation and Amortization	1	
Interest Expense	(1)	
Total Change in Operating Expenses and Other		(15)
Income Tax Credit		3
First Quarter of 2006		$ (5)

Net Income (Loss) decreased $6 million in the first quarter of 2006. The key driver of the decrease was a $15 million increase in Other Operation and Maintenance expenses, partially offset by a $6 million increase in Gross Margin.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of emission allowances and purchased power, were as follows:

- Retail and Off-system Sales Margins increased $3 million primarily due to an increase in capacity revenue.
- Other revenues increased $2 million primarily due to a settlement with an electric cooperative.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased $15 million. Maintenance expense increased $9 million primarily due to a $5 million increase in scheduled power plant maintenance and a $3 million increase in scheduled overhead line maintenance. Other Operation expense increased $6 million primarily due to increased customer-related expenses, factoring of accounts receivable and outside services.

Income Taxes

The $3 million increase in Income Tax Credit is primarily due to the increase in pretax book loss.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2006.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 10,922	$ 1,635	$ 12,557
Noncurrent Assets	11,068	103	11,171
Total MTM Derivative Contract Assets	21,990	1,738	23,728
Current Liabilities	(9,717)	(603)	(10,320)
Noncurrent Liabilities	(7,165)	(53)	(7,218)
Total MTM Derivative Contract Liabilities	(16,882)	(656)	(17,538)
Total MTM Derivative Contract Net Assets	$ 5,108	$ 1,082	$ 6,190

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 14,214
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	164
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(196)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(64)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(9,010)
Total MTM Risk Management Contract Net Assets	5,108
Net Cash Flow Hedge Contracts	1,082
Total MTM Risk Management Contract Net Assets at March 31, 2006	$ 6,190

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,151	$ 277	$ 123	$ (10)	$ -	$ -	$ 1,541
Prices Provided by Other External Sources - OTC Broker Quotes (a)	304	603	951	801	-	-	2,659
Prices Based on Models and Other Valuation Methods (b)	(455)	39	46	205	673	400	908
Total	$ 1,000	$ 919	$ 1,120	$ 996	$ 673	$ 400	$ 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 used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (629)	$ (483)	$ (1,112)
Changes in Fair Value	1,240	-	1,240
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	123	28	151
Ending Balance in AOCI March 31, 2006	$ 734	$ (455)	$ 279

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $592 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$93	$219	$118	$58	$311	$517	$246	$89

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $31 million and $34 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 339,601	$ 250,098
Sales to AEP Affiliates	14,068	2,632
Other	1,060	352
TOTAL	354,729	253,082
EXPENSES		
Fuel and Other Consumables for Electric Generation	213,173	134,178
Purchased Electricity for Resale	33,217	14,793
Purchased Electricity from AEP Affiliates	21,231	22,845
Other Operation	36,867	30,498
Maintenance	20,307	11,359
Depreciation and Amortization	21,021	22,619
Taxes Other Than Income Taxes	10,076	9,677
TOTAL	355,892	245,969
OPERATING INCOME (LOSS)	(1,163)	7,113
Other Income (Expense):		
Interest Income	569	165
Interest Expense	(9,135)	(7,875)
LOSS BEFORE INCOME TAXES	(9,729)	(597)
Income Tax Credit	(4,372)	(1,102)
NET INCOME (LOSS)	(5,357)	505
Preferred Stock Dividend Requirements	53	53
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (5,410)	$ 452

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

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 157,230	$ 230,016	$ 162,615	$ (1,264)	$ 548,597
Preferred Stock Dividends			(53)		(53)
TOTAL					548,544
COMPREHENSIVE LOSS					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $749				1,391	1,391
NET LOSS			(5,357)		(5,357)
TOTAL COMPREHENSIVE LOSS					(3,966)
MARCH 31, 2006	$ 157,230	$ 230,016	$ 157,205	$ 127	$ 544,578

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,190	$ 1,520
Accounts Receivable:		
Customers	29,004	37,740
Affiliated Companies	49,057	73,321
Miscellaneous	9,699	10,501
Allowance for Uncollectible Accounts	(290)	(240)
Total Accounts Receivable	87,470	121,322
Fuel	14,552	16,431
Materials and Supplies	40,450	38,545
Risk Management Assets	12,557	40,383
Accrued Tax Benefits	-	11,972
Regulatory Asset for Under-Recovered Fuel Costs	34,451	108,732
Prepayments and Other	8,195	14,287
TOTAL	198,865	353,192
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,086,284	1,072,928
Transmission	481,783	479,272
Distribution	1,156,783	1,140,535
Other	221,777	211,805
Construction Work in Progress	77,757	90,455
Total	3,024,384	2,994,995
Accumulated Depreciation and Amortization	1,178,101	1,175,858
TOTAL - NET	1,846,283	1,819,137
OTHER NONCURRENT ASSETS		
Regulatory Assets	36,159	50,723
Long-term Risk Management Assets	11,171	33,566
Employee Benefits and Pension Assets	81,607	82,559
Deferred Charges and Other	40,346	16,287
TOTAL	169,283	183,135
TOTAL ASSETS	$ 2,214,431	$ 2,355,464

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 118,815	$ 75,883
Accounts Payable:		
General	83,618	130,627
Affiliated Companies	57,135	89,786
Long-term Debt Due Within One Year – Affiliated	50,000	50,000
Risk Management Liabilities	10,320	38,243
Customer Deposits	40,788	53,844
Accrued Taxes	44,644	22,420
Other	28,500	51,548
TOTAL	433,820	512,351
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	521,086	521,071
Long-term Risk Management Liabilities	7,218	22,582
Deferred Income Taxes	413,991	436,382
Regulatory Liabilities and Deferred Investment Tax Credits	264,034	284,640
Deferred Credits and Other	24,442	24,579
TOTAL	1,230,771	1,289,254
TOTAL LIABILITIES	1,664,591	1,801,605
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 5)		
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	157,205	162,615
Accumulated Other Comprehensive Income (Loss)	127	(1,264)
TOTAL	544,578	548,597
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,214,431	$ 2,355,464

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income (Loss)	$ (5,357)	$ 505
Adjustments for Noncash Items:		
Depreciation and Amortization	21,021	22,619
Deferred Income Taxes	(23,436)	2,126
Mark-to-Market of Risk Management Contracts	9,106	10,473
Deferred Property Taxes	(24,295)	(24,368)
Change in Other Noncurrent Assets	11,229	(5,816)
Change in Other Noncurrent Liabilities	(20,806)	(9,579)
Changes in Components of Working Capital:		
Accounts Receivable, Net	33,852	14,815
Fuel, Materials and Supplies	(26)	(2,871)
Accounts Payable	(77,217)	(7,779)
Accrued Taxes, Net	34,196	14,982
Customer Deposits	(13,056)	110
Over/Under Fuel Recovery	74,281	40,895
Other Current Assets	6,086	2,285
Other Current Liabilities	(23,048)	(13,262)
Net Cash Flows From Operating Activities	2,530	45,135
INVESTING ACTIVITIES		
Construction Expenditures	(45,539)	(20,501)
Change in Other Cash Deposits, Net	6	-
Net Cash Flows Used For Investing Activities	(45,533)	(20,501)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	42,932	(15,414)
Principal Payments for Capital Lease Obligations	(206)	(148)
Dividends Paid on Common Stock	-	(8,500)
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Net Cash Flows From (Used For) Financing Activities	42,673	(24,115)
Net Increase (Decrease) in Cash and Cash Equivalents	(330)	519
Cash and Cash Equivalents at Beginning of Period	1,520	279
Cash and Cash Equivalents at End of Period	$ 1,190	$ 798

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $8,681,000 and $7,806,000 and for income taxes net of refunds was $575,000 and $(1,366,000) in 2006 and 2005, respectively. Noncash capital lease acquisitions were $564,000 and $551,000 in 2006 and 2005, respectively. Noncash Construction Expenditures included in Accounts Payable of $6,052,000 and $2,208,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

Results of Operations

First Quarter of 2006 Compared to First Quarter of 2005

Reconciliation of First Quarter of 2005 to First Quarter of 2006 Net Income (in millions)

First Quarter of 2005		$	12
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	13		
Transmission Revenues	3		
Other	8		
Total Change in Gross Margin			24
Changes in Operating Expenses and Other:			
Other Operation and Maintenance			(14)
Income Tax Expense			(4)
First Quarter of 2006		$	18

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $6 million to $18 million in the first quarter of 2006. The key driver of the increase was a $24 million increase in Gross Margin, offset by a $14 million increase in Other Operation and Maintenance expenses and a $4 million increase in Income Tax Expense.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $13 million compared to 2005 primarily due to a $5 million increase related to wholesale prices and an $8 million increase in capacity revenue.
- Transmission Revenues increased $3 million primarily due to higher rates within SPP.
- Other revenues increased $8 million primarily due to the gain on sale of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $14 million. This was primarily due to a $9 million increase in maintenance during scheduled power plant outages. In addition, Other Operation expense increased $2 million due to right-of-way clearing and increased tree trimming. Other Operation expense also increased $2 million primarily due to customer-related expenses and factoring of accounts receivable.

Income Taxes

The $4 million increase in Income Tax Expense is primarily due to the increase in pretax book income.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the three months ended March 31, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 3,049	$ 3,715
Net Cash Flows From (Used For):		
Operating Activities	41,293	54,957
Investing Activities	(54,294)	(34,751)
Financing Activities	12,501	(15,329)
Net Increase (Decrease) in Cash and Cash Equivalents	(500)	4,877
Cash and Cash Equivalents at End of Period	$ 2,549	$ 8,592

Operating Activities

Our Net Cash Flows From Operating Activities were $41 million in 2006. We produced Net Income of $18 million during the period and noncash expense items of $33 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $27 million inflow from Accounts Receivable, Net was due to lower affiliated energy transactions. The $18 million outflow from Fuel, Materials and Supplies was the result of reduced fuel consumption during scheduled power plant outages. The $45 million inflow from Accrued Taxes, Net was due to increased income taxes. We did not make a federal income tax payment in 2006. The $16 million outflow from Customer Deposits was due to lower trading-related deposits. In addition, our cash flow related to Over/Under Fuel Recovery was favorably impacted by the new fuel surcharges effective December 2005 in our Arkansas service territory and in January 2006 in our Texas service territory. The $15 million outflow from Accounts Payable was the result of lower expenditures related to tree trimming and right-of-way clearing, energy purchases and general operations.

Our Net Cash Flows From Operating Activities were $55 million in 2005. We produced Net Income of $12 million during the period and noncash expense items of $32 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 $15 million inflow from Accounts Receivable, Net was the result of decreased affiliated energy transactions. The $16 million inflow from Accrued Taxes, Net was primarily due to a reduction of income tax related accruals.

Investing Activities

Cash Flows Used For Investing Activities during 2006 and 2005 were $54 million and $35 million, respectively. The cash flows were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability. For the remainder of 2006, we expect our Construction Expenditures to be approximately $230 million.

Financing Activities

Cash Flows From Financing Activities were $13 million during 2006. During the quarter, the net change in short-term debt was $4 million. Long-term debt retirements were $2 million. In addition, we borrowed $21 million from the Utility Money Pool. We also paid $10 million in Common Stock Dividends.

Cash Flows Used For Financing Activities were $15 million during 2005. We retired $2 million of Notes Payable. We paid $13 million in Common Stock Dividends.

Financing Activity

Long-term debt retirements and principal payments during the first three months of 2006 were:

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable	$ 1,707	4.47	2011
Notes Payable	750	Variable	2008

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt retirements discussed above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring and Note 7 – Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 – Rate Matters, Note 4 – Customer Choice and Industry Restructuring and Note 5 – Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section beginning on page L-1. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of March 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of March 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 12,790	$ 1,911	$ 14,701
Noncurrent Assets	12,969	121	13,090
Total MTM Derivative Contract Assets	25,759	2,032	27,791
Current Liabilities	(11,410)	(724)	(12,134)
Noncurrent Liabilities	(8,430)	(107)	(8,537)
Total MTM Derivative Contract Liabilities	(19,840)	(831)	(20,671)
Total MTM Derivative Contract Net Assets	$ 5,919	$ 1,201	$ 7,120

MTM Risk Management Contract Net Assets
Three Month Ended March 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 16,387
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	30
Fair Value of New Contracts at Inception When Entered During the Period (a)	16
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(233)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	43
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(3,098)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(7,226)
Total MTM Risk Management Contract Net Assets	5,919
Net Cash Flow Hedge Contracts	1,201
Total MTM Risk Management Contract Net Assets at March 31, 2006	$ 7,120

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities 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, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,376	$ 324	$ 144	$ (11)	$ -	$ -	$ 1,833
Prices Provided by Other External Sources - OTC Broker Quotes (a)	342	720	1,116	936	-	-	3,114
Prices Based on Models and Other Valuation Methods (b)	(576)	17	38	240	786	467	972
Total	$ 1,142	$ 1,061	$ 1,298	$ 1,165	$ 786	$ 467	$ 5,919

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

(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to March 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (736)	$ (5,116)	$ (5,852)
Changes in Fair Value	1,449	-	1,449
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	144	135	279
Ending Balance in AOCI March 31, 2006	$ 857	$ (4,981)	$ (4,124)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $282 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Three Months Ended March 31, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$109	$256	$138	$68	$363	$604	$287	$104

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $27 million and $31 million at March 31, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
REVENUES		
Electric Generation, Transmission and Distribution	$ 293,993	$ 229,808
Sales to AEP Affiliates	10,765	17,122
Other	374	281
TOTAL	305,132	247,211
EXPENSES		
Fuel and Other Consumables for Electric Generation	90,661	90,418
Purchased Electricity for Resale	29,218	13,380
Purchased Electricity from AEP Affiliates	23,337	5,864
Other Operation	49,783	44,615
Maintenance	24,657	15,715
Depreciation and Amortization	32,534	32,393
Taxes Other Than Income Taxes	15,982	15,663
TOTAL	266,172	218,048
OPERATING INCOME	38,960	29,163
Other Income (Expense):		
Interest Income	543	455
Allowance for Equity Funds Used During Construction	185	649
Interest Expense	(12,771)	(12,780)
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST EXPENSE	26,917	17,487
Income Tax Expense	8,823	4,396
Minority Interest Expense	222	886
NET INCOME	17,872	12,205
Preferred Stock Dividend Requirements	57	57
EARNINGS APPLICABLE TO COMMON STOCK	$ 17,815	$ 12,148

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 135,660	$ 245,003	$ 407,844	$ (6,129)	$ 782,378
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(57)		(57)
TOTAL					772,321
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $930				1,728	1,728
NET INCOME			17,872		17,872
TOTAL COMPREHENSIVE INCOME					19,600
MARCH 31, 2006	$ 135,660	$ 245,003	$ 415,659	$ (4,401)	$ 791,921

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,549	$ 3,049
Accounts Receivable:		
Customers	44,030	47,515
Affiliated Companies	27,060	49,226
Miscellaneous	6,721	7,984
Allowance for Uncollectible Accounts	(482)	(548)
Total Accounts Receivable	77,329	104,177
Fuel	55,627	40,333
Materials and Supplies	37,048	34,821
Risk Management Assets	14,701	47,319
Regulatory Asset for Under-Recovered Fuel Costs	32,990	51,387
Prepayments and Other	23,330	34,010
TOTAL	243,574	315,096
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,660,255	1,660,392
Transmission	649,066	645,297
Distribution	1,167,991	1,153,026
Other	445,320	443,749
Construction Work in Progress	119,090	104,175
Total	4,041,722	4,006,639
Accumulated Depreciation and Amortization	1,782,450	1,776,216
TOTAL - NET	2,259,272	2,230,423
OTHER NONCURRENT ASSETS		
Regulatory Assets	72,372	81,776
Long-term Risk Management Assets	13,090	39,796
Employee Benefits and Pension Assets	82,165	83,330
Deferred Charges and Other	74,933	46,926
TOTAL	242,560	251,828
TOTAL ASSETS	$ 2,745,406	$ 2,797,347

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 49,198	$ 28,210
Accounts Payable:		
General	59,922	71,138
Affiliated Companies	51,510	53,019
Short-term Debt – Nonaffiliated	5,788	1,394
Long-term Debt Due Within One Year – Nonaffiliated	19,693	15,755
Risk Management Liabilities	12,134	45,098
Customer Deposits	34,987	50,848
Accrued Taxes	88,037	42,799
Other	58,000	82,699
TOTAL	379,269	390,960
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	672,476	678,886
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	8,537	27,083
Deferred Income Taxes	402,767	409,513
Regulatory Liabilities and Deferred Investment Tax Credits	306,120	320,066
Deferred Credits and Other	128,101	131,477
TOTAL	1,568,001	1,617,025
TOTAL LIABILITIES	1,947,270	2,007,985
Minority Interest	1,515	2,284
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Commitments and Contingencies (Note 5)		
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	415,659	407,844
Accumulated Other Comprehensive Income (Loss)	(4,401)	(6,129)
TOTAL	791,921	782,378
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,745,406	$ 2,797,347

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 17,872	$ 12,205
Adjustments for Noncash Items:		
Depreciation and Amortization	32,534	32,393
Deferred Income Taxes	(9,101)	(4,312)
Mark-to-Market of Risk Management Contracts	10,468	12,419
Deferred Property Taxes	(28,997)	(28,570)
Change in Other Noncurrent Assets	9,541	3,552
Change in Other Noncurrent Liabilities	(19,121)	(10,308)
Changes in Components of Working Capital:		
Accounts Receivable, Net	26,848	14,582
Fuel, Materials and Supplies	(17,521)	2,427
Accounts Payable	(15,304)	(6,021)
Accrued Taxes, Net	45,238	16,116
Customer Deposits	(15,861)	(866)
Over/Under Fuel Recovery, Net	15,216	8,451
Other Current Assets	10,736	4,849
Other Current Liabilities	(21,255)	(1,960)
Net Cash Flows From Operating Activities	41,293	54,957
INVESTING ACTIVITIES		
Construction Expenditures	(54,238)	(33,931)
Change in Advances to Affiliates, Net	-	(928)
Other	(56)	108
Net Cash Flows Used For Investing Activities	(54,294)	(34,751)
FINANCING ACTIVITIES		
Change in Short-term Debt, Net – Nonaffiliated	4,394	-
Retirement of Long-term Debt – Nonaffiliated	(2,457)	(2,457)
Change in Advances from Affiliates, Net	20,988	-
Principal Payments for Capital Lease Obligations	(367)	(315)
Dividends Paid on Common Stock	(10,000)	(12,500)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Net Cash Flows From (Used For) Financing Activities	12,501	(15,329)
Net Increase (Decrease) in Cash and Cash Equivalents	(500)	4,877
Cash and Cash Equivalents at Beginning of Period	3,049	3,715
Cash and Cash Equivalents at End of Period	$ 2,549	$ 8,592

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $11,892,000 and $12,304,000 and for income taxes net of refunds was $1,282,000 and $22,257,000 in 2006 and 2005, respectively. Noncash capital lease acquisitions were $3,412,000 and $1,329,000 in 2006 and 2005, respectively. Noncash Construction Expenditures included in Accounts Payable of $12,800,000 and $4,700,000 were outstanding as of March 31, 2006 and 2005, respectively.

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

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

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

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the 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.	Company-wide Staffing and Budget Review	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Assets Held for Sale	TCC
9.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
11.	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 2005 Annual Report as incorporated in and filed with the 2005 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 condensed balance sheets in the common shareholder's equity section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of March 31, 2006 and December 31, 2005 is shown in the following table.

Components	March 31, 2006	December 31, 2005
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (3,153)	$ (16,421)
CSPCo	3,182	(859)
I&M	740	(3,467)
KPCo	1,427	(194)
OPCo	6,931	755
PSO	279	(1,112)
SWEPCo	(4,124)	(5,852)
TCC	38	(224)
TNC	78	(111)
Minimum Pension Liability:		
APCo	$ (189)	$ (189)
CSPCo	(21)	(21)
I&M	(102)	(102)
KPCo	(29)	(29)
PSO	(152)	(152)
SWEPCo	(277)	(277)
TCC	(928)	(928)
TNC	(393)	(393)

Related Party Transactions

The amounts of power purchased from Ohio Valley Electric Corporation, which is 43.47 % owned by AEP and CSPCo, were:

Company	Three Months Ended March 31, 2006	2005
	(in thousands)	
APCo	$ 21,974	$ 16,952
CSPCo	5,665	4,594
I&M	8,552	6,113
OPCo	18,630	14,963

CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, on behalf of the AEP West companies, from January 1, 2005 to December 31, 2014. The PPA is for unit contingent power up to a maximum of 315 MW. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. The purchase of Sweeny power and its sale to nonaffiliates are shared among the AEP West companies under the CSW Operating Agreement. See Note 17 of the 2005 Annual Report for a discussion of the CSW Operating Agreement. The purchases from Sweeny were:

	Three Months Ended March 31,	
Company	**2006**	**2005**
	(in thousands)	
PSO	$ 11,693	$ 13,297
SWEPCo	17,547	7,494
TCC	582	2,072
TNC	3,831	5,652

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

The Registrant Subsidiaries' Statements of Operations were converted from a utility format presentation where only regulated cost-of-service items were reflected in Operating Income to a commercial format presentation where nonutility items are reflected as components of Operating Income.

These revisions had no impact on our previously reported results of operations, financial conditions or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

In December 2004, the FASB issued SFAS 123R. 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 Opinion No. 25, "Accounting for Stock Issued to Employees." The Registrant Subsidiaries recorded insignificant cumulative effects of a change in accounting principle in the first quarter of 2006 for the effects of initially applying the statement, primarily reflected in Other Operation on their financial statements.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. The Registrant Subsidiaries applied the principles of SAB 107 and the applicable FSPs in conjunction with their adoption of SFAS 123R.

The Registrant Subsidiaries adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires them to record compensation expense for all awards granted after the time of adoption and recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in the Registrant Subsidiaries' financial statements for the three months ended March 31, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Implementation of SFAS 123R did not materially affect the Registrant Subsidiaries' results of operations, cash flows or financial condition.

SFAS 156 "Accounting for Servicing of Financial Assets – An Amendment of FASB Statement No. 140" (SFAS 156)

In March 2006, the FASB issued SFAS 156. SFAS 156 requires an entity to recognize a servicing asset or servicing liability each time it undertakes an obligation to service a financial asset by entering into a servicing contract in certain situations and requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value, if practicable. SFAS 156 also requires separate presentation of servicing assets and servicing liabilities subsequently measured at fair value in the statement of financial position and additional disclosures for all separately recognized servicing assets and servicing liabilities. The requirements for recognition and initial measurement of servicing assets and servicing liabilities should be applied prospectively to all transactions after the effective date of this statement. This statement will be effective on January 1, 2007. Management has not completed the process of determining the effect of this statement on our financial statements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

The Rate Matters note within the 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations and cash flows. Rate proceedings that are not expected to adversely affect future results of operations and cash flows are not included in this report. The following sections discuss current activities and update the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs – Affecting APCo

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of $21 million of incremental E&R costs incurred from July 2004 through September 2005. Through March 31, 2006, APCo deferred $26 million of incurred E&R costs.

In January 2006, the Virginia SCC staff proposed that APCo recover current, rather than past, incremental E&R costs in its electric rates at an ongoing level of $20 million. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were established as a regulatory asset. Management believes the staff's position is contrary to the statute and an October 2005 Virginia SCC order, which denied APCo's original request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs that the commission found prudent.

Hearings concluded in March 2006. At the hearings, the staff amended its testimony to recommend a $24 million increase in APCo's ongoing rates. If the Virginia SCC reverses its position and adopts the staff's recommendation or denies recovery of any of APCo's deferred E&R costs, APCo's future results of operations and cash flows could be adversely impacted.

APCo Virginia Base Rate Case – Affecting APCo

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including an equity return. In addition, APCo requested to move off-system sales margins currently credited to customers through base rates to the fuel factor where they can be adjusted annually. This proposed off-system sales rate credit of $27 million partially offsets the $225 million requested increase in base rates for a net increase in revenues of $198 million. APCo requested that the new rates be implemented on an interim basis beginning in the June 2006 customer billings. We are unable to predict the ultimate effect of this filing on APCo's future revenues, cash flows and financial condition.

APCo West Virginia Rate Case – Affecting APCo

In April 2006, APCo and WPCo reached agreement with the WVPSC staff and intervenors in the West Virginia rate case filed in 2005. The parties filed a settlement agreement with the WVPSC, providing for an initial overall increase in APCo's rates of $40 million effective July 28, 2006. The initial annual increase in rates is comprised of :

- An Expanded Net Energy Cost (ENEC) increase of $50 million for fuel and purchased power expenses;
- A $21 million special construction surcharge providing recovery of the costs of the Wyoming-Jacksons Ferry 765 kV line and scrubbers to date;
- A general base rate reduction of $16 million of which a portion relates to a reduction in depreciation expense which affects cash flows but not earnings; and
- A $15 million credit for prior over-recoveries of ENEC costs, currently recorded in regulatory liabilities on the Condensed Consolidated Balance Sheets. Therefore, this item impacts cash flows but has no effect on earnings.

In addition, the agreement provides a mechanism that allows APCo to adjust its rates annually for the timely recovery of the ongoing investments in scrubbers at its Mountaineer and John Amos power plants. The estimated future annual increases based on the level of incremental investment in the scrubbers as proposed in the settlement, are projected to result in a $32 million increase in revenues effective July 1, 2007, a $13 million increase in revenues effective July 1, 2008 and a $16 million increase in revenues effective July 1, 2009. The settlement further provides for the reinstatement of ENEC proceedings and its related annual rate adjustment mechanism for changes in fuel and purchased power costs. Although the agreement is comprehensive in all respects, one issue regarding the rates for a special contract industrial customer remains unresolved. The WVPSC ordered legal briefs to be filed by May 4, 2006 with responses to be filed by May 15, 2006. At this time, the WVPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues and cash flows.

I&M Depreciation Study Filing– Affecting I&M

In December 2005, I&M filed a petition with the IURC, seeking authorization to revise the book depreciation rates applicable to its electric utility plant in service. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition is not a request for a change in customers' electric service rates. Intervenors filed testimony in March 2006 and I&M filed its rebuttal testimony in April 2006. Hearings are scheduled for May 2006. As proposed by I&M, the book depreciation expense reduction would increase its earnings, but would not impact cash flows. If approved by the IURC, I&M will currently adjust its book depreciation expense from the approved effective date forward. Management is unable to predict the outcome of this proceeding.

KPCo Rate Filing – Affecting KPCo

In March 2006, the KPSC approved the settlement agreement in KPCo's 2005 base rate case. The approved agreement provides for a $41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes.

PSO Fuel and Purchased Power and its Possible Impact on AEP East companies and AEP West Companies

In 2002, PSO under-recovered $44 million 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 proposed collection of those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 through 2003 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of $27 million to $37 million. In February 2006, the OCC staff filed a report regarding $9 million of the reallocation assigned to wholesale customers. In that report, the OCC staff concluded that the reallocation assigned to wholesale customers has been refunded, thus removing that issue from their recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has jurisdiction over that allocation. The PUCT appealed the ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals and will defend its position vigorously. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs or offsets under-recovered fuel deferrals with additional reallocated off-system sales margins, PSO's future results of operations and cash flows could be adversely affected. However, if the position taken by the federal court in Texas applies to PSO's case, the OCC could be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party may file a complaint at the FERC alleging the allocation of off-system sales margins adopted by PSO is improper which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on the AEP West companies' and AEP East companies' future results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Inquiry – Affecting SWEPCo

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEPCo PUCT Staff Review of Earnings – Affecting SWEPCo

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo that they will not further pursue the matter.

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

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court. The cities are appealing the appeals court decision to the Texas Supreme Court. Management cannot predict the outcome of further appeals, but a reversal of the favorable court of appeals decision regarding the loss of load issue could result in the issue being returned to the PUCT for further consideration. If the PUCT were to reverse its decision and order refunds of PTB revenues, it could adversely impact TCC's and TNC's results of operations and cash flows.

RTO Formation/Integration – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In 2005, the FERC approved the amortization of approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was $1 million in both the first quarter of 2006 and 2005.

The AEP East companies' deferred unamortized RTO formation/integration costs were as follows:

	March 31, 2006		December 31, 2005	
	PJM-Billed Integration Costs	**Non-PJM Billed Formation/ Integration Costs**	**PJM-Billed Integration Costs**	**Non-PJM Billed Formation/ Integration Costs**
		(in millions)		
APCo	$ 4.0	$ 4.8	$ 4.1	$ 4.9
CSPCo	1.6	1.9	1.7	1.9
I&M	3.1	3.5	3.2	3.7
KPCo	1.0	1.1	1.0	1.1
OPCo	4.5	5.0	4.7	5.1

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs not billed by PJM of $2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In 2005, the FERC denied a request AEP jointly filed with two other utilities to recover deferred PJM-billed integration costs from all load-serving entities in the PJM RTO zone over a ten-year period. Instead, the FERC ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In June 2005, AEP filed a request for rehearing. In October 2005, the FERC granted AEP's rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. In April 2006, a settlement was filed with the FERC that allows recovery of deferred PJM-billed integration costs from the PJM region over ten years. In addition, the settlement reduced the return on equity component included in the AEP East companies' carrying charge rates to 10.5%, which will have an immaterial impact on their future results of operations.

CSPCo, OPCo and KPCo recover the amortization of RTO formation/integration costs billed. APCo has not commenced recovery in West Virginia (where APCo filed a settlement agreement in its base rate case with the WVPSC that included the recovery of its amortization of these costs) or Virginia (where APCo filed a base rate case which includes recovery of these costs). I&M has not commenced recovery in Indiana where it is subject to a rate cap until June 30, 2007.

Until APCo and I&M can adjust their retail rates to recover the amortization of both RTO-related deferred costs, their results of operations and cash flows will be adversely affected by the amortizations. If the Virginia, West Virginia or Indiana commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs and no appeal is ultimately successful, it would have an adverse impact on APCo's or I&M's future results of operations and cash flows.

Transmission Rate Proceedings at the FERC - Affecting APCo, CSPCo, I&M, KPCo and OPCo

SECA Revenue

In accordance with FERC orders, the AEP East companies collected SECA rates to mitigate lost through-and-out transmission service (T&O) revenues through March 31, 2006, when SECA rates expired. The FERC set SECA rate issues for hearing and indicated that the SECA rate revenues are subject to refund or surcharge. Intervenors in the SECA proceeding are objecting to the SECA rates and the method of determining those rates. The SECA hearings are scheduled to begin in early May 2006. At this time, management is unable to determine the outcome of the FERC's SECA rate proceeding and if it will impact the AEP East companies' future results of operations and cash flows.

The AEP East companies recognized net SECA revenues as follows:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	Total Net SECA Revenues Through March 2006
	(in millions)		
APCo	$ 11.0	$ 8.6	$ 55.5
CSPCo	6.5	4.4	30.8
I&M	6.7	4.9	32.7
KPCo	2.7	2.0	13.2
OPCo	8.6	6.1	42.2

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement allowing increases to the AEP East companies' wholesale transmission rates in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues were eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when APCO's Wyoming-Jacksons Ferry transmission line enters service, currently expected in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided with their owned extra-high-voltage facilities that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under AEP's proposed Highway/Byway rate design, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design. In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include 500 kV and higher existing facilities and some facilities at lower voltages in the Highway rate. Another proposal uses facilities 200 kV or higher in the Highway rate. These alternative Highway/Byway proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM rate design. In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. Hearings were held in April 2006.

The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the transmission-owning AEP East companies. The competing Highway/Byway proposals filed by others would also produce incremental net revenues to the AEP East transmission-owning companies, but at a much lower level. The staff rate design would produce slightly more net revenue for the AEP East companies than the original AEP/AP proposal. Management cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on the AEP East companies' revenues and results of operations, compared to the continuation of the PJM rates that went into effect on April 1, 2006 when the SECA rates expired.

As of March 31, 2006, SECA transition rates did not fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through retail rate proceedings. The status of the retail rate proceedings are as follows:

- In Kentucky, KPCo settled a rate case, which provides for the recovery of the transmission revenue shortfall.
- APCo filed a settlement agreement in West Virginia, which included recovery of the lost T&O/SECA transmission revenues.
- A pending rate request filed in February 2006 in Ohio addresses the significant reduction in FERC transmission revenues.
- In Virginia, APCo filed a request for revised rates, which includes recovery of the lost T&O/SECA transmission revenues.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.

Management is unable to predict whether the FERC will approve a regional rate to mitigate the loss of T&O/SECA revenues, or if not, when, and if, the effect of the loss of T&O/SECA transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

The AEP East companies' future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates, or the FERC's review of previously collected SECA rates results in a refund to customers.

Allocation Agreement between AEP East companies and AEP West companies – Affecting the AEP East companies and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved AEP's proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of cost recovery mechanisms by state.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of AEP's twelve electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Michigan, Virginia and Texas) in which the AEP electric utility companies operate. The Customer Choice and Industry Restructuring note in the 2005 Annual Report should be read in conjunction with this report 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 in those states and updates the 2005 Annual Report.

TEXAS RESTRUCTURING – Affecting TCC, TNC and SWEPCo

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was $1.475 billion, which included carrying costs through September 2005. An order on rehearing was issued by the PUCT in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. TCC expects to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties may appeal the PUCT's order claiming it permits TCC to over-recover its stranded costs.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting to securitize $1.8 billion of net stranded generation plant costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which are partially offsetting in nature. These obligations total $491 million and would be payable through a CTC over a period determined by the PUCT. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony in April 2006. Hearings are scheduled for May. It is possible that the PUCT could reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, a negative impact on the timing of cash flows could result. Cash flows from securitization would be adversely impacted if the PUCT reduces TCC's computation of the amount to be securitized.

The PUCT has not addressed the allocation of stranded costs to TCC's wholesale jurisdiction. TCC estimates the amount allocated to wholesale to be less than $1 million, while intervenors and PUCT staff filed testimony recommending that $77 million of stranded costs be allocated to TCC's wholesale jurisdiction. TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize or recover.

Consistent with certain prior securitization determinations, the PUCT may deduct the cost-of-money benefit of accumulated deferred federal income taxes (ADFIT) from the securitization request. Then, the future cost-of-money benefit would be transferred to a separate regulatory asset recoverable in normal delivery rates outside of the securitization process, which would affect the timing of cash recovery. TCC estimates the total cost-of-money benefit to be $328 million, which TCC plans to include in its estimated CTC request. Intervenors filed testimony recommending an increase in this amount, along with the retrospective ADFIT amounts, by as much as $175 million.

In addition, the intervenors raised three issues totaling $138 million which were addressed by the PUCT in prior proceedings - the appropriate interest rate for both stranded cost and deferred fuel and the treatment of excess earnings refunds. Other issues raised by the intervenors dealt with the amounts to be securitized versus refunded to customers through the CTC, customer class allocation issues and debt defeasance strategies.

The difference between the recorded securitizable true-up regulatory asset of $1.5 billion at March 31, 2006 and TCC's securitization request of $1.8 billion is detailed in the table below:

	(in millions)
Stranded Generation Plant Costs	$ 969
Net Generation-related Regulatory Asset	249
Excess Earnings	(49)
Recorded Securitizable Net Stranded Generation Plant Costs	1,169
Recorded Debt Carrying Costs on Recorded Net Stranded Generation Plant Costs	284
Recorded Securitizable True-up Regulatory Asset	1,453
Unrecorded But Recoverable Equity Carrying Costs	212
Unrecorded Estimated April 2006 – August 2006 Debt Carrying Costs	40
Unrecorded Securitization Issuance Costs	24
Unrecorded Excess Earnings, Related Return and Other	75
Securitization Request	$ 1,804

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up order, the PUCT reduced net stranded generation plant costs by $51 million related to the present value of accumulated deferred investment tax credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers may be a violation of the Internal Revenue Code's normalization provisions. The federal tax statutes require public utilities to "normalize" or synchronize the tax benefits derived from ADITC and EDFIT with the financial and regulatory life of the regulated plant assets that give rise to the benefit. The normalization rules prohibit returning the benefits to ratepayers faster than the underlying assets are recovered for rate purposes. Once these assets are no longer regulated, the normalization provisions do not permit these benefits to be returned to ratepayers. In the true-up order, the PUCT agreed to consider revisiting this issue if the IRS ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded securitizable true-up regulatory asset in the above reconciliation.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. On April 21, 2006 the IRS informed TCC that they are ruling against the PUCT treatment and consider the flow-through of ADITC and EDFIT a normalization violation.

In a motion for rehearing, TCC asked the PUCT to reconsider its treatment of ADITC and EDFIT in light of the position of the IRS. In its order on rehearing, the PUCT declined to change its treatment. The PUCT withdrew the language stating it would revisit the issue if their treatment was ruled a normalization violation by the IRS and replaced it with an additional explanation of the basis for its original decision. In a motion for a second rehearing filed April 24, 2006, TCC informed the PUCT that the IRS intended to rule adversely on the private letter ruling request.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of March 31, 2006 and also a loss of the accelerated tax depreciation election in the future. Management intends to continue working with the PUCT to avoid a normalization violation that would adversely affect TCC's future results of operations and cash flows.

CTC Proceeding for Other True-up Items

TCC incurs carrying costs on the net negative other true-up regulatory liability balances until fully refunded. The principal components of the CTC rate reduction are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance. TCC anticipates filing to implement a negative CTC (as a rate reduction) for its net other true-up items in the second quarter of 2006.

The difference between the components of TCC's recorded net regulatory liabilities – other true-up items as of March 31, 2006 and its planned CTC proceeding request are detailed below:

	(in millions)
Wholesale Capacity Auction True-up	$ 61
Carrying Costs on Wholesale Capacity Auction True-up	17
Retail Clawback	(61)
Deferred Over-recovered Fuel Balance	(177)
Recorded Net Regulatory Liabilities – Other True-up Items	(160)
ADFIT Benefit	(328)
Unrecorded Carrying Costs and Other	(3)
Estimated CTC Request	$ (491)

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the same ruling should result. The impact of the favorable Federal District court order, if upheld on appeal, could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, it may file a complaint at the FERC to address the allocation issue. Management is unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. An unfavorable FERC ruling may result in a reallocation of off-system sales margins from AEP East companies to AEP West companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets Impacting Securitization and CTC Proceedings

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate from its unbundled cost of service rate proceeding. The recorded embedded debt component of the carrying cost rate is 8.12%. Through March 2006, TCC recorded $301 million of debt-related carrying costs ($284 million on stranded generation plant costs impacting the securitization proceeding and $17 million on wholesale capacity auction true-up impacting the CTC proceeding). The remaining equity component of $166 million will be recognized in income as collected. TCC will continue to accrue a debt-related carrying cost until its net true-up regulatory asset is fully recovered. Equity carrying costs are recognized in income as collected.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% overall carrying cost rate on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period from the date of adoption. TCC received an order in the True-up Proceeding in February 2006 and an order on rehearing in April 2006 (which is subject to rehearing). TCC asserted in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order. If adopted retroactively, it would have an adverse effect on future results of operations and cash flows.

Summary

TCC's recorded securitizable true-up regulatory asset at March 31, 2006 of $1.5 billion, net of regulatory liabilities – other true-up items of $160 million, accurately reflects the PUCT's order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges would be more than sufficient to recover TCC's recorded net true-up regulatory asset. As a result, TCC has not recorded any additional impairment. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its true-up or subsequent proceedings, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods established by the PUCT in future securitization and CTC proceedings. If TCC determines in future securitization and CTC proceedings that it is probable it cannot recover a portion of the recorded net true-up regulatory asset and is able to estimate the amount of such nonrecovery, it would record a provision for such amount which could have an adverse effect on its future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. It is expected that municipal customers and other intervenors will also pursue vigorously court appeals to further reduce TCC's true-up recoveries. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings, requested rehearings or court appeals. If municipal customers and other intervenors succeed in their expected appeals, it could have a material adverse effect on TCC's future results of operations, cash flows and financial condition.

Texas Restructuring - SPP

In April 2006, the PUCT proposed a possible delay in customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for the IGCC Plant (see "IGCC Plant" section of this note below). OPCo's potential for the additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for the IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $8 million for CSPCo and $20 million for OPCo in the first quarter of 2006 from all the RSP recoveries less the amortization of RSP deferrals net of the recognition of equity carrying charges from 2004 and 2005.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In Dayton Power & Light Company's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In another Ohio Supreme Court decision involving FirstEnergy Corporation's Ohio electric companies, the Court held that the PUCO-approved RSPs for FirstEnergy Corporation's Ohio electric companies did not comply with the statutory provision regarding the availability of a competitive bid alternative for customers. The Ohio companies believe their RSPs are factually different from FirstEnergy Corporation's Ohio electric companies' RSPs and comply with the applicable statute. However, if the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo and OPCo's future earnings will be adversely affected. In addition, if the RSP order were determined on appeal to be illegal in its entirety under the Ohio Electric Restructuring Act of 1999, it would have an initial adverse effect on results of operations, cash flows and possibly financial condition. Although the Ohio companies believe that the RSP plan is legal and intend to defend vigorously the PUCO's order, they cannot predict the ultimate outcome of the pending litigation.

IGCC Plant

In March 2005, the Ohio companies 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 proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, recovery of construction-financing costs; and Phase 3, recovery, or refund, in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008 under their RSPs. As of March 31, 2006, CSPCo and OPCo each deferred $5 million of pre-construction IGCC costs.

On April 10, 2006, the PUCO issued an order finding that the PUCO has the jurisdiction to approve the proposed cost recovery and authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. The Ohio companies filed a tariff to recover Phase 1 pre-construction costs over a twelve-month period. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

Transmission Rate Filing

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month following the date when AEP's Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur on June 30, 2006. The Ohio companies anticipate, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 and increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing intends to recover the new OATT rates resulting from the settlement of the March 2005 filing with the FERC requesting increased OATT rates in a three-step increase. In March 2006, the PUCO suspended the effective date of the new rates to provide its staff additional time to conduct its review of the application. In their application, the Ohio companies requested permission to defer for future recovery their unrecovered transmission costs as a result of the loss of SECA revenues starting April 1, 2006 if the PUCO did not issue an order in this case in time to implement the increase on April 1, 2006. If the PUCO does not approve the future recovery of the unrecovered transmission costs effective April 1, 2006 when the SECA revenues ceased, results of operations and cash flows will be adversely affected.

Storm Cost Recovery Filing

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously-expensed costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately $12 million of such costs.

PUCO Staff Report on Service Reliability

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In April 2006, the staff of the PUCO submitted a commission-ordered investigative report on the Ohio companies' compliance with the stipulation agreement. In the report, the staff asserted that the Ohio companies failed to fulfill all the terms of the stipulation agreement. The staff recommended various consequences for the PUCO's consideration, including the potential for civil forfeitures, monthly payments until the terms of the stipulation agreement have been met and providing credits to customers. The staff also suggested that the PUCO could explore possible improvements in the Ohio companies' management of the reliability process. Finally, the staff recommended that the Ohio companies file, in a companion docket, a comprehensive plan to improve their system reliability. The PUCO ordered the Ohio companies to respond to the staff's recommendations concerning consequences by May 23, 2006, after which the PUCO will determine how to proceed. In the companion docket, the PUCO directed the Ohio companies to prepare a plan to enhance service reliability. A timeline for submission of that plan has not been set. The PUCO indicated that it will set a procedural schedule in the future. Although the Ohio companies believe that they have substantially met the terms and expectations of the stipulation agreement, they cannot predict the outcome of these proceedings. If the PUCO adopts the staff's recommendations, the Ohio companies' results of operations and cash flows could be adversely affected.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through March 31, 2006, CSPCo incurred $50 million and deferred $26 million and OPCo incurred $51 million and deferred $27 million of such costs for probable future recovery in distribution rates. Through March 31, 2006, CSPCo and OPCo have not recorded $4 million each of equity carrying costs, which are not recognized until collected. Recovery of these regulatory assets is subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSPs, recovery of these amounts is deferred until the next distribution rate filing to change rates after December 31, 2008. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on the Ohio companies' future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within the 2005 Annual Report, certain Registrant Subsidiaries continue to be involved in various legal matters. The 2005 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 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in the 2005 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 that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued. A bench trial on remedy issues is scheduled for January 2007.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned) and Stuart (26% owned) stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases have been resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues have been filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule and the Federal EPA filed a petition for rehearing that case. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

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

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In July 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims – Affecting AEP East Companies and West Companies

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendant's power plants constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal was appealed to the Second Circuit Court of Appeals. Briefing has been completed and the case is scheduled to be argued this summer. Management believes the actions are without merit and intends to defend vigorously against the claims.

Ontario Litigation – Affecting CSPCo and OPCo

In June 2005, CSPCo, OPCo and nineteen nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. AEP has not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted $NO_{X,}$ SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. Management believes CSPCo and OPCo have meritorious defenses to this action and intend to defend vigorously against it.

OPERATIONAL

Power Generation Facility and TEM Litigation – 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 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to 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. AEP alleged that TEM breached the PPA, and sought a determination of its rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under the PPA; (ii) would seek a declaration from the District Court that the PPA was terminated; and (iii) would pursue against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. OPCo asked the court to modify the judgment to (i) award a termination payment to OPCo under the terms of the PPA; (ii) grant OPCo's attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted AEP's motion for reconsideration concerning TEM's parent guaranty and increased AEP's judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional $50 million damage award.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, OPCo could be adversely affected to the extent OPCo is unable to find other purchasers of the power with similar contractual terms and to the extent claimed termination value damages are not fully recovered from TEM.

FERC Long-term Contracts – Affecting AEP East Companies and AEP West Companies

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in AEP's favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities' request for a rehearing was denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

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 of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At March 31, 2006, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, each with a maturity of March 2007.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $55 million with maturity dates ranging from July 2006 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. At March 31, 2006, 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

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to March 31, 2006, TCC entered into sales agreements with a maximum indemnification exposure of $443 million related to the sale price of its generation assets. See "Texas Plants – South Texas Project" and "Texas Plants – TCC and TNC Generation Assets" sections of Note 10 of the 2005 Annual Report. There are no material liabilities recorded for any indemnifications.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At March 31, 2006, 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	$ 7
CSPCo	3
I&M	4
KPCo	2
OPCo	6
PSO	5
SWEPCo	5
TCC	6
TNC	3

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

In 2005, primarily in the second quarter, the Registrant Subsidiaries recorded severance benefits expense (primarily in Other Operation) resulting from a company-wide staffing and budget review. The expense included the allocation of approximately $19 million of severance benefits associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees but received allocated expenses.

Remaining accruals, reflected primarily in Current Liabilities – Other, ranged from $8 thousand to $1.1 million as of December 31, 2005. Payments and accrual adjustments recorded during the first quarter of 2006 were immaterial. Settlement of the remaining accruals, ranging from $5 thousand to $600 thousand as of March 31, 2006, are expected by the end of the second quarter of 2006.

8. ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station - Affecting TCC

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread) but subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsfield (the "nonaffiliated co-owners"). By May 2004, TCC received notice from the 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 the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in Dallas County, Texas State District Court by Golden Spread. Golden Spread alleges that the Public Utilities Board of the City of Brownsfield exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread on October 10, 2005. TCC and the nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. The case was briefed and argued before the court and is awaiting a decision. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its future results of operations. TCC's assets related to the Oklaunion Power Station have been classified as Assets Held for Sale – Texas Generation Plants on TCC's Condensed Consolidated Balance Sheets at March 31, 2006 and December 31, 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by the Registrant Subsidiaries.

Assets Held for Sale at March 31, 2006 and December 31, 2005 are as follows:

Texas Plants (TCC)	**March 31, 2006**	**December 31, 2005**
Assets:	**(in millions)**	
Other Current Assets	$ 1	$ 1
Property, Plant and Equipment, Net	43	43
Total Assets Held for Sale - Texas Generation Plants	$ 44	$ 44

9. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2006 and 2005:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2006	**2005**	**2006**	**2005**
	(in millions)			
Service Cost	$ 24	$ 23	$ 10	$ 11
Interest Cost	57	56	25	27
Expected Return on Plan Assets	(83)	(77)	(23)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	20	13	5	7
Net Periodic Benefit Cost	$ 18	$ 15	$ 24	$ 29

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiaries for the three months ended March 31, 2006 and 2005:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
APCo	$ 1,468	$ 1,848	$ 4,489	$ 5,345
CSPCo	205	534	1,805	2,222
I&M	2,331	2,365	2,953	3,631
KPCo	358	376	513	603
OPCo	826	1,206	3,396	3,827
PSO	977	72	1,588	1,869
SWEPCo	1,225	364	1,578	1,837
TCC	773	(219)	1,696	2,008
TNC	325	41	715	877

10. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business except AEGCo, which is an electricity generation business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2006 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 50,275	Variable	2036

In April 2006, APCo issued $250 million, 5.55% senior notes due in 2011 and $250 million, 6.375% senior notes due in 2036. The proceeds were used for general corporate purposes including funding the construction program, repaying advances from affiliates and replenishing working capital.

In April 2006, OPCo incurred obligations of $65 million relating to variable rate pollution control bonds due in 2036. The proceeds will be used to finance the cost of solid waste disposal facilities at the Mitchell Generating Station.

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	First Mortgage Bonds	$ 100,000	6.80	2006
APCo	Other Debt	3	13.718	2026
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	Securitization Bonds	30,641	5.01	2010

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

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
TCC	Notes Payable	$ 125,000	5.14	2007

Retirements:
NONE

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The Utility Money Pool participants' money pool activity and corresponding authorized limits for the three months ended March 31, 2006 are described in the following table:

Three Months Ended March 31, 2006:

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, 2006	Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 58,209	$ -	$ 23,516	$ -	$ (13,317)	$ 125,000
APCo	283,872	-	201,590	-	(164,192)	600,000
CSPCo	48,337	24,779	18,021	14,168	6,867	350,000
I&M	128,071	-	92,774	-	(49,137)	500,000
KPCo	20,659	5,923	9,175	1,583	5,923	200,000
OPCo	181,450	-	104,183	-	(81,043)	600,000
PSO	118,815	-	66,273	-	(118,815)	300,000
SWEPCo	58,124	-	37,848	-	(49,198)	350,000
TCC	117,429	49,193	87,094	32,347	32,101	600,000
TNC	14,513	34,574	5,000	13,339	3,046	250,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2006 and 2005 were 4.85% and 4.37% and 2.96% and 1.63%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2006 and 2005 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Three Months Ended March 31, 2006	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Three Months Ended March 31, 2005	Average Interest Rate for Funds Loaned to the Utility Money Pool for Three Months Ended March 31, 2006	Average Interest Rate for Funds Loaned to the Utility Money Pool for Three Months Ended March 31, 2005
		(in percentage)		
AEGCo	4.57	2.00	-	-
APCo	4.60	1.96	-	2.15
CSPCo	4.58	-	4.66	2.10
I&M	4.59	2.14	-	2.12
KPCo	4.54	-	4.75	2.15
OPCo	4.60	-	-	2.14
PSO	4.63	2.11	-	-
SWEPCo	4.60	-	-	2.13
TCC	4.47	2.27	4.68	2.12
TNC	4.57	-	4.54	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 2005 Annual Report should be read in conjunction with this report.

Environmental Matters

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

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

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units.

Clean Air Act Requirements

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

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

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

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

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

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

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

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

Estimated Air Quality Environmental Investments

As discussed in the 2005 Annual Report, the CAIR and CAMR programs described above will require significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Management's estimates, disclosed in the 2005 Annual Report, are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation, required levels of reductions, methods for allocation of allowances and selected compliance alternatives. In short, management cannot estimate compliance costs with certainty.

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

Potential Regulation of CO_2 Emissions

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

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was challenged in the courts and upheld. A petition to appeal to the U.S. Supreme Court has been filed. While mandatory requirements to reduce CO_2 emissions at our power plants do not appear to be imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases have been resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued. A bench trial on remedy issues is scheduled for January 2007.

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

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues have been filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule and the Federal EPA filed a petition for rehearing in that case. The Federal EPA also recently proposed a rule that would define “emissions increases” in a way that most of the challenged activities would be excluded from NSR.

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

Other Environmental Concerns

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

Adoption of New Accounting Pronouncements

Beginning in 2006, the Registrant Subsidiaries adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, the trend in the Registrant Subsidiaries' quarter-over-quarter net income (loss) is not materially different. See Note 2 – New Accounting Pronouncements in the Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries for further discussion.

CONTROLS AND PROCEDURES

During the first quarter of 2006, management, including the principal executive officer and principal financial officer of each 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 SEC'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, 2006, 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 the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2006 that materially affected, or is reasonably likely to materially affect, the Registrants' 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 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2005 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2005 Annual Report on Form 10-K. No new risk factors have been identified during the quarter ended March 31, 2006.

General Risks of Our Regulated Operations

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

On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental costs through June 30, 2006. The $62 million request included incurred and projected costs of environmental controls, transmission costs (including line construction) and other system reliability work. In October 2005, the Virginia SCC ruled that it does not have the authority to approve the recovery of projected costs. In November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery to $21 million. The staff of the Virginia SCC made filings to dismiss the transmission system reliability costs from consideration for recovery, arguing that the FERC, and not the Virginia SCC, has jurisdiction over the unbundled transmission component of APCo's retail rates. Through March 31, 2006, APCo deferred $26 million of recorded costs that are subject to this proceeding. The staff of the Virginia SCC issued testimony that would reduce APCo's recovery of current and future costs to $20 million. Hearings concluded in March 2006. At the hearings, the staff amended its testimony to recommend a $24 million increase in APCo's ongoing rates. If the Virginia SCC reverses its decision and adopts the staff's recommendation or denies recovery of any of APCo's deferred costs, it would adversely impact future results of operations and cash flows.

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

In August 2005, APCo and WPCo collectively filed an application (amended in January 2006) with the WVPSC seeking an initial increase in their retail base rates of approximately $74 million. Most of the requested base rate increase is attributable to reactivating the currently suspended ENEC mechanism that provides recovery of power supply costs, including fuel and purchased power, while the rest is primarily related to recovery of costs associated with the Ceredo Generating Station and service reliability improvements. The first supplemental increase of $9 million, requested to be effective at the same time as the base rate change, provides for recovery of the capital costs of the Wyoming-Jackson's Ferry 765kV line. The remaining proposed supplemental increases are $44 million, $10 million and $38 million, to be effective on January 1, 2007, 2008 and 2009, respectively, and provide for recovery of environmental expenditures. APCo has a regulatory liability of $52 million of pre-suspension, previously over-recovered ENEC costs which, along with a carrying cost, it is proposing to apply in the future to any future under-recoveries of ENEC costs through the reactivated ENEC mechanism. The WVPSC granted a joint motion that requested hearings begin in April 2006, that new rates go into effect on July 28, 2006 and that deferral accounting for over- or under-recovery of the ENEC begin July 1, 2006. In April 2006, the parties filed a settlement agreement with the WVPSC. The WVPSC has not approved the settlement agreement and therefore, we are unable to predict the ultimate effect of this filing on future revenues, results of operations and cash flows.

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

The Kentucky Public Service Commission approved our pending Kentucky base rate case settlement agreement in March 2006. Therefore, this risk factor is no longer applicable.

Risks Related to Owning and Operating Generating Assets and Selling Power

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

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and PJM expanded regions (Combined Footprint). The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement SECA transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision and SECA fees of $174 million were collected subject to refund while FERC considers the issue. Hearings are scheduled for May 2006.

SECA transition rates have not fully compensated AEP for lost T&O revenues. SECA transition rates expired at the end of March 2006, and all transmission costs that would otherwise have been covered by T&O rates in the Combined Footprint are now subject to recovery from native load customers of AEP's East zone public utility subsidiaries. A rate request is pending in West Virginia that addresses the reduction in these transmission revenues. In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. At this time, management is unable to predict whether any resultant increase in rates applicable to AEP's internal load will be recoverable on a timely basis from state retail customers.

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

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

We have agreed to lease from Juniper Capital L.P. a non-regulated merchant power generation facility ("Facility") near Plaquemine, Louisiana. We sublease the Facility to Dow. We operate the Facility for Dow. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to Tractebel at a price that is currently in excess of market. Tractebel alleged that the power purchase agreement was unenforceable. This agreement is now being litigated. A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that Tractebel had breached the contract and awarded us damages of $123 million plus prejudgment interest. Both parties have filed appeals. In January 2006, the trial court increased AEP's judgment against Tractebel to $173 million plus prejudgment interest. In March 2006, the trial judge amended the January 2006 order to eliminate the additional $50 million damage award. If the trial award is reversed or if Tractebel does not pay the judgment, our cash flow will be adversely affected. If the power agreement is held to be unenforceable, we will be required to find new purchasers for up to 800 MW. There can be no assurance that the power produced will be sold at prices that will exceed our costs to produce it. If that were the case, as a result of our obligations to Dow, we would be required to operate the Facility at a loss.

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, 2006 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
01/01/06 – 01/31/06	-	$ -	-	$ -
02/01/06 – 02/28/06	-	-	-	-
03/01/06 – 03/31/06	80	78.00	-	-
Total	80	$ 78.00	-	$ -

(a) TNC repurchased 80 shares of its 4.40% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

Item 5. **Other Information**

On April 6, 2006, AEP entered into (i) an Amended and Restated $1.5 billion Credit Agreement, dated as of April 6, 2006 (the “2010 Credit Agreement”) among AEP, a group of banks and JPMorgan Chase Bank, N.A., as Administrative Agent, and (ii) an Amended and Restated $1.5 billion Credit Agreement, dated as of April 6, 2006 (the “2011 Credit Agreement” and, together the 2010 Credit Agreement, the “Credit Agreements”) among AEP, a group of banks and Barclays Bank PLC, as Administrative Agent. The Credit Agreements are available for working capital and other general corporate purposes of AEP. AEP also has the ability to issue letters of credit against the Credit Agreements in an amount up to $200 million per Credit Agreement. The 2010 Credit Agreement expires on March 30, 2010 and the 2011 Credit Agreement expires on April 6, 2011.

Borrowings under the Credit Agreements are available upon customary terms and conditions for facilities of this type. AEP also is required to maintain its percentage of debt to total capitalization at a level that does not exceed 67.5%.

The 2010 Credit Agreement amends and restates a $1.5 billion credit agreement previously maturing in March 2010, and the 2011 Credit Agreement amends and restates a $1 billion credit agreement previously maturing in May 2007.

Item 6. Exhibits

AEP, PSO, SWEPCo

10(a) – Restated and Amended Operating Agreement among PSO, SWEPCo and AEPSC. Issued on February 10, 2006, effective May 1, 2006
10(b) – Restated and Amended Operating Agreement among PSO, SWEPCo and AEPSC. Issued on February 10, 2006, effective May 1, 2006

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

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP

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.

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 5, 2006