2006 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Financial Discussion and Analysis

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO ANNUAL REPORTS

GLOSSARY OF TERMS

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

Term	Meaning
ADFIT	Accumulated Deferred Federal Income Taxes.
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
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 generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
ECAR	East Central Area Reliability Council.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company, a former AEP subsidiary.

IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IKEC	Indiana-Kentucky Electric Corporation, a subsidiary of OVEC.
IPP	Independent Power Producer.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
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.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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.
PUHCA	Public Utility Holding Company Act.
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.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor’s.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.

SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
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.
TC	Transition Charge.
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, costs 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, soot or particulate matter 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.
- 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.
- 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 the potential for new legislation or regulation in Ohio and/or Virginia and membership in and integration into regional transmission organizations.
- 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.

The registrants expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

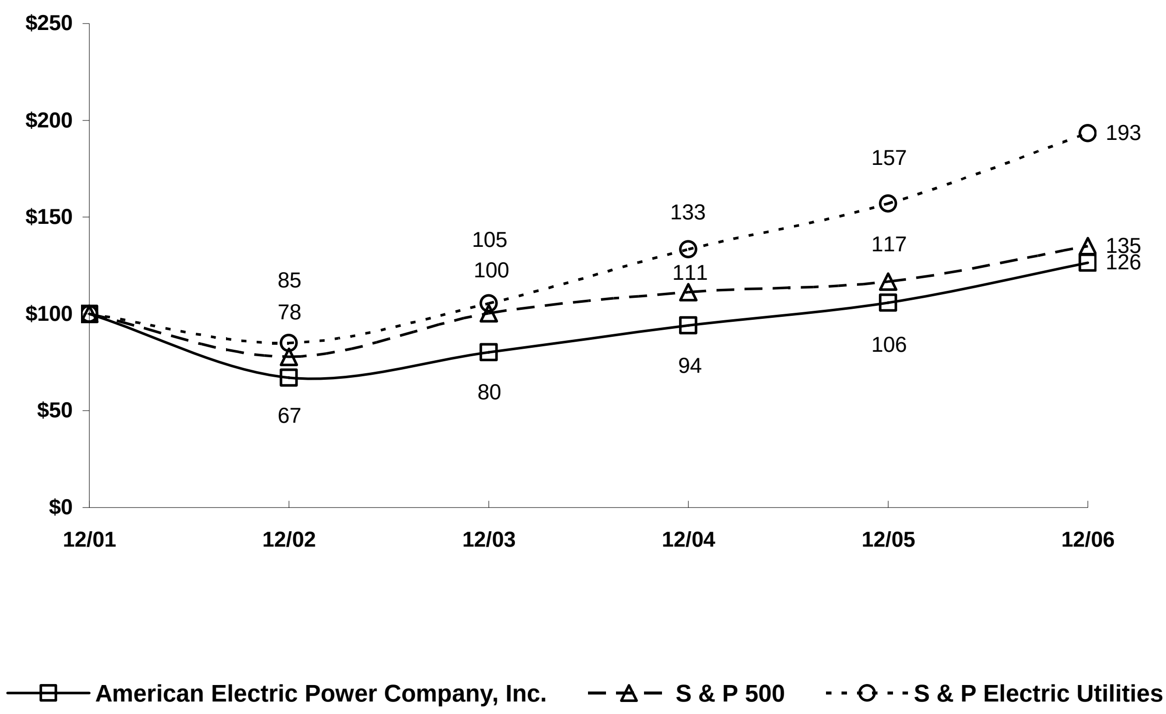
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2006	$ 43.13	$ 36.49	$ 42.58	$ 0.39
September 30, 2006	37.30	34.10	36.37	0.37
June 30, 2006	35.19	32.27	34.25	0.37
March 31, 2006	38.48	33.96	34.02	0.37
December 31, 2005	40.80	35.57	37.09	0.37
September 30, 2005	39.84	36.34	39.70	0.35
June 30, 2005	37.00	33.79	36.87	0.35
March 31, 2005	36.34	32.25	34.06	0.35

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2006, AEP had approximately 112,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., The S & P 500 Index
And The S & P Electric Utilities Index



* $100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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

	2006	2005	2004	2003	2002
			(in millions)		
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 12,622	$ 12,111	$ 14,245	$ 14,833	$ 13,641
Operating Income	$ 1,966	$ 1,927	$ 1,983	$ 1,743	$ 1,930
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 992	$ 1,029	$ 1,127	$ 522	$ 485
Discontinued Operations, Net of Tax	10	27	83	(605)	(654)
Extraordinary Loss, Net of Tax	-	(225)	(121)	-	-
Cumulative Effect of Accounting Changes, Net of Tax	-	(17)	-	193	(350)
Net Income (Loss)	$ 1,002	$ 814	$ 1,089	$ 110	$ (519)
BALANCE SHEETS DATA			(in millions)		
Property, Plant and Equipment	$ 42,021	$ 39,121	$ 37,294	$ 36,031	$ 34,132
Accumulated Depreciation and Amortization	15,240	14,837	14,493	14,014	13,544
Net Property, Plant and Equipment	$ 26,781	$ 24,284	$ 22,801	$ 22,017	$ 20,588
Total Assets	$ 37,987	$ 36,172	$ 34,636	$ 36,736	$ 36,003
Common Shareholders' Equity	$ 9,412	$ 9,088	$ 8,515	$ 7,874	$ 7,064
Cumulative Preferred Stocks of Subsidiaries	$ 61	$ 61	$ 127	$ 137	$ 145
Trust Preferred Securities (a)	$ -	$ -	$ -	$ -	$ 321
Long-term Debt (b)	$ 13,698	$ 12,226	$ 12,287	$ 14,101	$ 10,190
Obligations Under Capital Leases (b)	$ 291	$ 251	$ 243	$ 182	$ 228
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.52	$ 2.64	$ 2.85	$ 1.35	$ 1.46
Discontinued Operations, Net of Tax	0.02	0.07	0.21	(1.57)	(1.97)
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)	-	-
Cumulative Effect of Accounting Changes, Net of Tax	-	(0.04)	-	0.51	(1.06)
Basic Earnings (Loss) Per Share	$ 2.54	$ 2.09	$ 2.75	$ 0.29	$ (1.57)
Weighted Average Number of Basic Shares Outstanding (in millions)	394	390	396	385	332
Market Price Range:					
High	$ 43.13	$ 40.80	$ 35.53	$ 31.51	$ 48.80
Low	$ 32.27	$ 32.25	$ 28.50	$ 19.01	$ 15.10
Year-end Market Price	$ 42.58	$ 37.09	$ 34.34	$ 30.51	$ 27.33
Cash Dividends Paid per Common Share	$ 1.50	$ 1.42	$ 1.40	$ 1.65	$ 2.40
Dividend Payout Ratio	59.1%	67.9%	50.9%	569.0%	(152.9)%
Book Value per Share	$ 23.73	$ 23.08	$ 21.51	$ 19.93	$ 20.85

(a) See "Trust Preferred Securities" section of Note 15.

(b) Including portion due within one year.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Almost 36,000 megawatts of generating capacity as of December 31, 2006, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in many of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 207,632 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (more than 8,300 railcars, 2,600 barges, 51 towboats and one active coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

BUSINESS STRATEGY

Our mission is to bring comfort to our customers, support business and commerce and build strong communities. We invest in our core utility business operations to execute our mission. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. We plan to buy or build additional generation to meet franchise service obligations. Our plan entails designing, building, improving and operating reasonably priced, environmentally-compliant, efficient sources of power and maximizing the amount of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary, our business strategy is to:

- Respect our employees and give them the opportunity to be as successful as they can be.
- Meet the energy needs of our customers in ways that improve their quality of life and protect the environment today and for generations to come.
- Improve the environmental and safety performance of our generating fleet, and grow that fleet.
- Set the standards for safety, efficiency and reliability in our electric transmission and distribution systems.
- Nurture strong and productive relationships with public officials and regulators.
- Provide leadership, integrity and compassion as a corporate citizen to every community we serve.

OUTLOOK FOR 2007

We remain focused on the fundamental earning power of our utilities and committed to maintaining our credit quality. To achieve our goals we plan to:

- Obtain permits and continue to pursue federal tax credits for our proposed IGCC plants in Ohio and West Virginia and move forward with the engineering and design of these plants.
- Begin construction of over 2,000 MW of new generation in Arkansas, Louisiana and Oklahoma with commercial operation dates ranging from 2007 through 2012.
- Purchase 1,576 MW of additional gas-fired generating unit capacity.
- Invest in transmission projects such as the AEP Interstate Project, the Electric Transmission Texas Project, a joint venture with MidAmerican Energy Holdings Company (MidAmerican), and others to ensure competitive energy prices for electric consumers in and around congested areas.
- Maintain our strong financial condition and credit ratings.
- Control our operating and maintenance costs.
- Obtain favorable resolutions to our numerous rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

There are, nevertheless, certain risks and challenges including:

- Regulatory activity in Virginia, Texas, Oklahoma, Ohio and with the FERC.
- Legislative activity in Ohio and Virginia regarding future regulatory operating environment.
- Fuel cost volatility and fuel cost recovery, including related transportation issues.
- Wholesale market volatility.
- Plant availability.
- Weather.

Regulatory Activity

In 2007, our significant regulatory activities will include:

- Pursuit of favorable resolutions of our pending base rate cases in Virginia, Texas and Oklahoma.
- Influence of key legislative outcomes regarding Ohio and Virginia's future regulatory operating environment.
- Legal proceedings regarding appeals related to Texas stranded cost recoveries.
- Continued regulatory proceedings before the FERC seeking:
  - proper regional transmission rates in our eastern transmission zone,
  - approval of SECA rates collected subject to refund through March 31, 2006 and
  - approval and incentives to construct a 550-mile 765 kV transmission line project in the PJM footprint.
- Our request before the PUCT regarding new transmission rates and designation as a utility for Electric Transmission Texas LLC, our joint venture with MidAmerican.

Fuel Costs

During 2006, spot market prices for coal and natural gas declined. In contrast, market prices for fuel oil increased and continue to be volatile. We still experienced an eight percent increase in coal costs during 2006 and expect a seven to nine percent increase in 2007 even considering softening fuel markets and favorable transportation effects during the year. The increase is primarily due to expiring lower priced contracts being replaced with new higher priced contracts. We have price risk related to these commodity prices. We do not have an active fuel cost recovery adjustment mechanism in Ohio, which represents approximately 20% of our fuel costs. 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 incurred under-recoveries of $26 million for 2006 and expect additional under-recoveries through June 2007.

Our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans. These increased rates, along with the reinstated fuel cost adjustment rate clause for over- or under-recovery of fuel, off-system sales margins, certain transmission items and related costs effective July 1, 2006 in West Virginia, will help offset future negative impacts of fuel price increases on our gross margins.

Capital Expenditures

Our current projections call for capital expenditures of approximately $9.9 billion from 2007-2009. For 2007, we forecast approximately $3.5 billion in construction expenditures, excluding allowances for funds used during construction. We also forecast purchases of additional gas-fired generating units for a total of $427 million. Our current projections are as follows:

	(in millions)
Generation	$ 996
Distribution	848
Environmental	935
Transmission	496
Corporate	165
Total Construction Expenditures	3,440
Purchases of Gas-Fired Units	427
Total Capital Expenditures	$ 3,867

Off-System Sales

In 2007, we expect a decline in off-system sales revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power. This decline is primarily due to expected increases in sales to municipal and energy cooperative customers and demand for electricity from our native load retail customers including Ormet, which reduces the amount of power available for off-system sales. In addition, lower expected generating plant availability due to environmental retrofit outages likely will result in lower off-system sales.

Corporate Sustainability Reporting

Our first Corporate Responsibility report will be published and available in 2007. In 2004 a subcommittee of the Policy Committee of our Board of Directors prepared a report entitled, “An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies.” While the 2004 report was quite well received, it primarily addressed environmental issues we face. The scope of our 2007 report will reach beyond environmental issues and address other matters that create risk to our sustainability into the future. The report will be developed using the sustainability reporting guidelines issued by the Global Reporting Initiative and will address issues such as leadership, strategy and management, workforce issues including safety and health, climate change and energy security, reliability and growth.

2006 RESULTS

We had a year of continued improvement and many accomplishments in 2006. Our total shareholder return was 18.8% and we increased our quarterly dividend 5.4% to $0.39 per share.

We continued receiving favorable outcomes in various regulatory activities resulting in increased revenues. We continued securing new power supply contracts with municipal and cooperative customers and our barging subsidiary produced strong results. Some of these positive factors were offset in part by mild weather and an impairment loss from the sale of the Plaquemine Cogeneration Facility to Dow Chemical Company.

We announced plans for new generation in Oklahoma, Louisiana and Arkansas; continued work on engineering and design on new clean-coal plants in Ohio and West Virginia; announced a proposal to build a 550-mile, 765-kilovolt transmission line from West Virginia to New Jersey to address west-east power flow and congestion issues in PJM; announced a joint venture with MidAmerican to build much needed transmission capacity in Texas and we agreed to purchase additional gas-fired generating plants in 2007 to address capacity concerns in the east.

Our regulatory accomplishments include the implementation of new base rates in Ohio, Kentucky, West Virginia and Virginia (subject to refund) and we have taken a step forward in resolving the rate design issues related to our FERC transmission rates. Although various legal issues remain to be decided, we received a final order in our Texas True-up Proceeding and in October 2006 we received proceeds of $1.7 billion related to the securitization of our Texas regulatory assets. We received approval for our request to increase rates for recovery of incremental environmental and reliability costs in Virginia.

RESULTS OF OPERATIONS

Segments

Our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio and Virginia continue to have commission-determined transition rates. Virginia is currently considering returning to regulation for generation. While our Utility Operations segment remains our primary business segment, the emergence of other areas of our business prompted us to identify two new business segments in 2006. One of these new segments is our MEMCO Operations segment, which reflects our significant ongoing barging activities. We also identified our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. We no longer consider Investments – Gas Operations and Investments – UK Operations as reportable segments because we have sold substantially all of those assets.

Starting in the fourth quarter of 2006, our new 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.

MEMCO Operations

- Bulk commodity barging operations.

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change for the years ended December 31, 2006, 2005 and 2004 (Earnings and Weighted Average Number of Basic Shares Outstanding in millions). We reclassified prior year amounts to conform to the current year's presentation.

	2006		2005		2004	
	Earnings	**EPS (b)**	**Earnings**	**EPS (b)**	**Earnings**	**EPS (b)**
Utility Operations	$ 1,028	$ 2.61	$ 1,018	$ 2.61	$ 1,175	$ 2.97
MEMCO Operations	80	0.20	21	0.05	12	0.03
Generation and Marketing	12	0.03	16	0.04	73	0.18
All Other (a)	(128)	(0.32)	(26)	(0.06)	(133)	(0.33)
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 992	$ 2.52	$ 1,029	$ 2.64	$ 1,127	$ 2.85
Weighted Average Number of Basic Shares Outstanding		394		390		396

(a) All Other includes:
- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

(b) 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.

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2006 decreased $37 million compared to 2005 primarily due to a $136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility offset by a $59 million increase in MEMCO Operations earnings. Utility Operations earnings increased $10 million due to new retail rates implemented in Ohio, Kentucky, Oklahoma, Virginia and West Virginia mostly offset by unfavorable weather, decreases in transmission revenues from the loss of SECA rates and increases in regulatory amortization and operating expenses.

Average basic shares outstanding increased to 394 million in 2006 from 390 million in 2005 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 397 million as of December 31, 2006.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2005 decreased $98 million compared to 2004 primarily due to gains on sales of equity investments in 2004 and a decrease in recorded stranded generation carrying costs income in 2005, as a result of the PUCT decisions related to TCC's True-up Proceeding.

Average basic shares outstanding decreased to 390 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program executed in 2005. Actual shares outstanding were 394 million as of December 31, 2005.

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 in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	2006	**2005**	**2004**
		(in millions)	
Revenues	$ 12,011	$ 11,389	$ 10,764
Fuel and Purchased Power	4,669	4,288	3,704
Gross Margin	7,342	7,101	7,060
Depreciation and Amortization	1,435	1,315	1,281
Other Operating Expenses	3,843	3,801	3,749
Operating Income	2,064	1,985	2,030
Other Income, Net	177	103	330
Interest Charges and Preferred Stock Dividend Requirements	670	595	627
Income Tax Expense	543	475	558
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 1,028	$ 1,018	$ 1,175

Summary of Selected Sales and Weather Data
For Utility Operations
For the Years Ended December 31, 2006, 2005 and 2004

	2006	2005	2004
Energy Summary		(in millions of KWH)	
Retail:			
Residential	47,222	48,720	45,770
Commercial	38,579	38,605	37,203
Industrial	53,914	53,217	51,484
Miscellaneous	2,653	2,745	3,252
Total Retail (a)	142,368	143,287	137,709
Wholesale	44,564	47,785	57,409
Texas Wires Delivery	26,382	26,525	25,581
Total KWHs	213,314	217,597	220,699

(a) Does not include retail sales to Texas Commercial and Industrial (Texas C&I) customers, which are included in the Generation and Marketing segment. Sales by Texas C&I were formerly included in the Utility Operations segment. Total KWHs sold to Texas C&I customers were 296 million, 470 million and 911 million for 2006, 2005 and 2004, respectively.

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. In general, degree day changes in our eastern region have a larger effect on results of operations than changes in our western region due to the relative size of the two regions and the associated number of customers within each. Cooling degree days and heating degree days in our service territory for the years ended December 31, 2006, 2005 and 2004 were as follows:

	2006	2005	2004
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,477	3,130	2,992
Normal – Heating (b)	3,078	3,088	3,086
Actual – Cooling (c)	923	1,153	877
Normal – Cooling (b)	985	969	974
Western Region (d)			
Actual – Heating (a)	1,172	1,377	1,382
Normal – Heating (b)	1,605	1,615	1,624
Actual – Cooling (c)	2,430	2,386	2,006
Normal – Cooling (b)	2,175	2,150	2,149

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

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$ 1,018
Changes in Gross Margin:		
Retail Margins	352	
Off-system Sales	(18)	
Transmission Revenues	(140)	
Other Revenues	47	
Total Change in Gross Margin		241
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(39)	
Asset Impairments and Other Related Charges	39	
Gain on Dispositions of Assets, Net	(50)	
Depreciation and Amortization	(120)	
Taxes Other Than Income Taxes	8	
Carrying Costs Income	59	
Other Income, Net	15	
Interest and Other Charges	(75)	
Total Change in Operating Expenses and Other		(163)
Income Tax Expense		(68)
Year Ended December 31, 2006		$ 1,028

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change increased $10 million to $1,028 million in 2006. The key driver of the increase was a $241 million increase in Gross Margin offset by a $163 million increase in Operating Expenses and Other and a $68 million increase in Income Tax Expense.

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

- Retail Margins increased $352 million primarily due to the following:
  - A $244 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a $67 million increase related to new rates implemented in other East jurisdictions of Kentucky, West Virginia and Virginia (subject to refund) and a $13 million increase related to new rates implemented in Oklahoma in June 2005.
  - A $123 million increase related to increased usage and customer growth of which $63 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005.
  - A $70 million increase related to increased sales to municipal, cooperative and other customers primarily as a result of new power supply contracts.
  - A $55 million increase related to decreased sharing of off-system sales margins with retail customers due to lower off-system sales and changes in the SIA.

  These increases were partially offset by:
  - A $148 million increase in delivered fuel cost, which relates to the AEP East companies with inactive, capped or frozen fuel clauses.
  - A $95 million decrease in usage related to mild weather. As compared to the prior year, our eastern region and western region experienced 21% and 15% declines, respectively, in heating degree days. Also compared to the prior year, our eastern region experienced a 20% decrease in cooling degree days.

- Margins from Off-system Sales decreased $18 million primarily due to lower generation availability in the west due to the sale of STP in May 2005, a reversal of a Texas regulatory provision in 2005 and lower margins from trading activities mostly offset by higher margins in the east.
- Transmission Revenues decreased $140 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $34 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. We have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other Revenues increased $47 million primarily due to the sale of emission allowances and increased securitization revenues.

Utility Operating Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased $39 million primarily due to increases in generation expenses related to base operations and maintenance, distribution expenses related to vegetation management and service reliability, expenses at the Plaquemine Cogeneration Facility and favorable insurance adjustments which reduced expenses in 2005. These increases were partially offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana and the recovery of the ice storm expenses in Ohio in 2006 and a decrease in severance costs related to the 2005 staffing and budget review.
- Asset Impairments and Other Related Charges were $39 million in 2005 due to our retirement of two units at our Conesville Plant.
- Gain on Disposition of Assets, Net decreased $50 million primarily 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 reached a settlement with Centrica and 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 $120 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases, increased Texas amortization of the securitized transition assets and higher depreciable property balances.
- Carrying Costs Income increased $59 million primarily due to negative adjustments in 2005 related to the Texas True-up Proceeding orders received from the PUCT and an increase related to the Virginia environmental and reliability deferred costs.
- Interest and Other Charges increased $75 million primarily due to additional debt issued in late 2005 and in 2006 and increasing interest rates, partially offset by an increase in allowance for borrowed funds used during construction.
- Income Tax Expense increased $68 million due to an increase in pretax income, state income taxes, changes in certain book/tax differences accounted for on a flow-through basis and the recording of tax reserve adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 1,175
Changes in Gross Margin:		
Retail Margins	67	
Off-system Sales	17	
Transmission Revenues	(57)	
Other Revenues	14	
Total Change in Gross Margin		41
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(92)	
Asset Impairments and Other Related Charges	(39)	
Gain on Dispositions of Assets, Net	116	
Depreciation and Amortization	(34)	
Taxes Other Than Income Taxes	(37)	
Other Income, Net	(227)	
Interest and Other Charges	32	
Total Change in Operating Expenses and Other		(281)
Income Tax Expense		83
Year Ended December 31, 2005		$ 1,018

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change decreased $157 million to $1,018 million in 2005. Key driver of the decrease included a $281 million increase in Operating Expenses and Other, offset in part by a $41 million increase in Gross Margin and an $83 million decrease in Income Tax Expense.

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

- The increase in Retail Margins from our utility segment over the prior year was due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. The higher usage was primarily weather-related as cooling degree days increased 31% and 19% for the East and West, respectively. This load growth was partially offset by higher delivered fuel costs of approximately $129 million, of which the majority relates to our East companies with inactive fuel clauses.
- Margins from Off-system Sales for 2005 were $17 million higher than in 2004 due to favorable price margins partially offset by a decrease in gross margin principally due to the sale of almost all of our Texas generation assets to support Texas stranded cost recovery.
- Transmission Revenues decreased $57 million primarily due to the loss of through-and-out rates as mandated by the FERC.

Utility Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $92 million due to an $87 million increase in generation expense related to strong retail and wholesale sales and capacity requirements, increased plant maintenance in 2005 and PJM expenses of $30 million. Additionally, distribution maintenance expense increased $91 million from tree trimming and reliability work. These increases were partially offset by reduced administrative and general expenses of $90 million.
- Asset Impairments and Other Related Charges for 2005 included a $39 million impairment related to the retirement of two units at CSPCo's Conesville Plant.

- Gain on Dispositions of Assets, Net increased $116 million resulting from the receipt of net 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. We reached an agreement with Centrica in March 2005 resolving disputes back to 2002 on how such amounts were calculated.
- Depreciation and Amortization expense increased $34 million primarily due to a higher depreciable asset base.
- Taxes Other Than Income Taxes increased $37 million due to increased property tax values and assessments and higher state excise taxes due to the increase in taxable KWH sales.
- Other Income, Net decreased $227 million primarily due to the following:
  - A $321 million decrease related to carrying costs recorded by TCC on its net stranded generation costs and its capacity auction true-up asset. In 2004, TCC booked $302 million of carrying costs income related to 2002 through 2004. Upon receipt of the final order in February 2006 in TCC's True-up Proceeding, we determined that adjustments to those carrying costs were required, resulting in carrying costs expense of $19 million in 2005 for TCC.

  This decrease was offset by:
  - A $56 million increase related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
  - A $20 million increase related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.
  - A $14 million increase related to the establishment of regulatory assets for carrying costs on environmental and reliability deferred costs for APCo.
- Interest and Other Charges decreased $32 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates and the retirement of debt in 2004 and 2005.
- Income Tax Expense decreased $83 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

MEMCO Operations

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment increased from $21 million in 2005 to $80 million in 2006. The increase was primarily related to strong demand and a tight supply of barges resulting in increased barge freight rates and utilization. Additionally, 2006 operating conditions for our barging operations improved from 2005 when hurricanes, severe ice and flooding caused increased operating costs.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment increased from $12 million in 2004 to $21 million in 2005. The increase was primarily related to favorable barging activity due to strong demand and a tight supply of barges, resulting in a 45% increase in freight rates between 2004 and 2005.

Generation and Marketing

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment in 2006 was essentially flat when compared to 2005.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment decreased from $73 million in 2004 to $16 million in 2005. The decrease was primarily due to a $64 million after-tax gain on the sale of our equity investments in the Colorado and Florida independent power producers in 2004.

All Other

2006 Compared to 2005

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from All Other increased from a $26 million loss in 2005 to a $128 million loss in 2006. The increase primarily relates to the $136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility, partially offset by lower interest expense and associated buyback costs related to the redemption of $550 million of senior unsecured notes in April 2005.

2005 Compared to 2004

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change decreased from a $133 million loss in 2004 to a $26 million loss in 2005. The 2005 results include only one-month of HPL's operations compared to a full year of HPL operations in 2004 due to the sale of HPL in January of 2005. We also resolved a portion of our outstanding Enron litigation in 2005 resulting in a net of tax settlement cost of approximately $28 million.

AEP System Income Taxes

Income Tax Expense increased $55 million between 2005 and 2006 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 and the recording of tax reserve adjustments.

Income Tax Expense decreased $142 million between 2004 and 2005 primarily due to a decrease in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by the recording of the tax return adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2006, we maintained our strong financial condition as reflected by the following actions and events:

- We maintained stable credit ratings across the AEP System including our rated subsidiaries;
- We issued $1.74 billion of securitization bonds for Texas stranded costs; and
- Standard and Poor's improved our business risk profile rating from six to five.

Debt and Equity Capitalization

	December 31, 2006		December 31, 2005	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 13,698	59.1%	$ 12,226	57.2%
Short-term Debt	18	0.0	10	0.0
Total Debt	13,716	59.1	12,236	57.2
Common Equity	9,412	40.6	9,088	42.5
Preferred Stock	61	0.3	61	0.3
Total Debt and Equity Capitalization	$ 23,189	100.0%	$ 21,385	100.0%

As a consequence of the capital changes during 2006, primarily the issuance of the securitization bonds and the adoption of SFAS 158, our ratio of debt to total capital increased from 57.2% to 59.1%.

In September 2006, the FASB issued SFAS 158 related to phase one of its pension and postretirement benefit accounting project. The new standard requires the recognition of a liability for 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. The adoption during the fourth quarter of 2006 resulted in a negative impact on our common equity at December 31, 2006 due to the recognition of a $235 million net of tax accumulated other comprehensive income reduction to common equity for those jurisdictions where we could not record a regulatory asset.

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 December 31, 2006, our available liquidity was approximately $3.3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2010
Revolving Credit Facility	1,500	April 2011
Total	3,000	
Cash and Cash Equivalents	301	
Total Lquidity Sources	3,301	
Less: Letters of Credit Drawn	26	
Net Available Liquidity	$ 3,275	

In 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, each with an option to issue up to $200 million as letters of credit.

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 December 31, 2006, this contractually-defined percentage was 54.0%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 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.

The two revolving credit facilities do not contain a material adverse change clause in the event of a draw on either facility.

Under a regulatory order, our utility subsidiaries, other than TCC, cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% of its capital. In addition, this order restricts those 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 December 31, 2006, all applicable utility subsidiaries complied with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2006, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 387 consecutive quarters. The Board of Directors increased the quarterly dividend from $0.37 to $0.39 per share in October 2006. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time.

Credit Ratings

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

Managing our cash flows is a major factor in maintaining our liquidity strength.

	2006	2005	2004
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 401	$ 320	$ 778
Net Cash Flows From Operating Activities	2,732	1,877	2,711
Net Cash Flows Used For Investing Activities	(3,743)	(1,005)	(329)
Net Cash Flows From (Used For) Financing Activities	911	(791)	(2,840)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	81	(458)
Cash and Cash Equivalents at End of Period	$ 301	$ 401	$ 320

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 December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2006 was $325 million. The weighted-average interest rate of our commercial paper during 2006 was 4.96%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is 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. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	2006	2005	2004
		(in millions)	
Net Income	$ 1,002	$ 814	$ 1,089
Less: Discontinued Operations, Net of Tax	(10)	(27)	(83)
Income Before Discontinued Operations	992	787	1,006
Noncash Items Included in Earnings	1,535	1,494	1,315
Changes in Assets and Liabilities	205	(404)	390
Net Cash Flows From Operating Activities	$ 2,732	$ 1,877	$ 2,711

Net Cash Flows From Operating Activities increased in 2006 because we did not make a pension contribution in 2006 compared with a $626 million contribution in 2005 and increased recovery of deferred fuel. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of increased fuel costs.

Net Cash Flows From Operating Activities were approximately $2.7 billion in 2006 consisting primarily of Income Before Discontinued Operations of $992 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. Under-recovered fuel costs decreased due to recoveries under proceedings we initiated in Oklahoma, Texas, Virginia and Arkansas during 2005. 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 is a $232 million decrease in cash related to customer deposits held for trading activities generally due to lower gas and power market prices.

Net Cash Flows From Operating Activities were approximately $1.9 billion in 2005. We produced Income Before Discontinued Operations of $787 million. Income Before Discontinued Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. We made contributions of $626 million to our pension trusts. Under-recovered fuel costs increased due to the higher cost of fuel, especially natural gas. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. 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 $140 million cash increase from Accounts Payable due to higher fuel and allowance acquisition costs not paid at December 31, 2005 and an increase in Customer Deposits held for trading activities of $157 million related to market prices.

Net Cash Flows From Operating Activities were $2.7 billion in 2004 consisting of our Income Before Discontinued Operations of $1 billion and noncash charges of $1.6 billion for depreciation, amortization and deferred taxes. We recorded $302 million in noncash income for carrying costs on Texas stranded cost recovery and recognized an after-tax, noncash Extraordinary Loss of $121 million to provide for probable disallowances to TCC's stranded generation costs. We realized gains of $157 million on sales of assets, primarily the IPPs and our South Coast equity investment. We made $231 million of contributions to our pension trusts. 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. Changes in working capital items resulted in cash from operations of $430 million predominantly due to increased accrued income taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

	2006	2005	2004
		(in millions)	
Construction Expenditures	$ (3,528)	$ (2,404)	$ (1,637)
Change in Other Temporary Cash Investments, Net	(33)	76	32
Investment in Discontinued Operations, Net	-	-	(59)
Purchases/Sales of Investment Securities, Net	(279)	98	46
Acquisitions of Assets	-	(360)	-
Proceeds from Sales of Assets	186	1,606	1,357
Other	(89)	(21)	(68)
Net Cash Flows Used for Investing Activities	$ (3,743)	$ (1,005)	$ (329)

Net Cash Flows Used For Investing Activities were $3.7 billion in 2006 primarily due to Construction Expenditures for our environmental investment plan. In our normal course of business, we purchase investment securities including auction rate securities and variable rate demand notes with cash available for short-term investments. These amounts also include purchases and sales of securities within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $1.0 billion in 2005 primarily due to Construction Expenditures being partially offset by the proceeds from the sales of HPL and STP. The sales were part of an announced plan to divest noncore investments and assets and a requirement of collecting stranded costs in Texas. Construction Expenditures increased due to our environmental investment plan.

Net Cash Flows Used For Investing Activities were $329 million in 2004. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.6 billion were distributed across our system, of which the most significant expenditures were investments for environmental improvements of $350 million and for a high voltage transmission line of $75 million. During 2004, we sold our U.K. generation, Jefferson Island Storage, LIG and certain IPP and TCC generation assets and used the proceeds from the sales of these assets to reduce debt.

We forecast approximately $3.5 billion of construction expenditures for 2007 plus $427 million for announced purchases of gas-fired generating units. 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, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	2006	2005	2004
		(in millions)	
Issuance of Common Stock	$ 99	$ 402	$ 17
Repurchase of Common Stock	-	(427)	-
Issuance/Retirement of Debt, Net	1,420	(91)	(2,238)
Dividends Paid on Common Stock	(591)	(553)	(555)
Other	(17)	(122)	(64)
Net Cash Flows From (Used for) Financing Activities	$ 911	$ (791)	$ (2,840)

Net Cash Flows From Financing Activities were $911 million in 2006 primarily due to issuance of the Texas Securitization Bonds. We paid common stock dividends of $591 million and issued and retired debt securities. See Note 15.

In 2005, we used $791 million of cash to pay dividends, buy back stock, retire preferred stock and reduce debt.

In 2004, we used $2.8 billion of cash to reduce debt and pay common stock dividends. We achieved our goal of reducing debt below 60% of total capitalization by December 31, 2004. The debt reductions were primarily funded with proceeds from our various divestitures during 2004.

The following financing activities occurred during 2006:

Common Stock:

- During 2006, we issued 2,955,898 shares of common stock under our incentive compensation and dividend reinvestment plans and received net proceeds of $99 million.

Debt:

- During 2006, we issued approximately $3.4 billion of long-term debt, including approximately $264 million of pollution control revenue bonds, $1.4 billion of senior notes and $1.7 billion of securitization bonds for Texas stranded costs. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions and construction programs.
- During 2006, we entered into $898 million of interest rate derivatives and settled $1.2 billion of such transactions. The settlements resulted in a net cash expenditure of $8 million. As of December 31, 2006, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $200 million in order to hedge a portion of anticipated 2007 issuances.
- At December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. As of December 31, 2006, we had no commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $325 million in March 2006 and the weighted average interest rate of commercial paper outstanding during the year was 4.96%.

Our capital investment plans for 2007 will require additional funding from the capital markets.

Off-balance Sheet Arrangements

Under a limited set of circumstances, we enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current 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. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and, in accordance with GAAP, are not required to consolidate these entities. We continue to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires August 24, 2007. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1.2 billion as of December 31, 2006.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 14. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

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. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 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 railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 18	$ -	$ -	$ -	$ 18
Interest on Fixed Rate Portion of Long-term Debt (b)	619	1,144	981	5,244	7,988
Fixed Rate Portion of Long-term Debt (c)	1,126	1,050	1,823	8,162	12,161
Variable Rate Portion of Long-term Debt (d)	143	85	88	1,277	1,593
Capital Lease Obligations (e)	90	117	43	126	376
Noncancelable Operating Leases (e)	331	599	490	1,893	3,313
Fuel Purchase Contracts (f)	2,499	3,892	3,090	8,299	17,780
Energy and Capacity Purchase Contracts (g)	199	352	306	408	1,265
Construction Contracts for Capital Assets (h)	1,728	645	29	945	3,347
Total	$ 6,753	$ 7,884	$ 6,850	$ 26,354	$ 47,841

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.50% and 6.35% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9 to the consolidated financial statements, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trusts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2006, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a) (b)	$ 26	$ -	$ -	$ -	$ 26
Guarantees of the Performance of Outside Parties (b)	-	-	-	85	85
Guarantees of Our Performance (c)	1,943	1,376	7	20	3,346
Transmission Facilities for Third Parties (d)	21	12	-	-	33
Total Commercial Commitments	$ 1,990	$ 1,388	$ 7	$ 105	$ 3,490

(a) We issue standby letters of credit to third parties. These letters of credit, issued in our ordinary course of business, cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. The maximum future payments of these letters of credit are $26 million with maturities ranging from March 2007 to November 2007. As the parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn.

(b) See “Guarantees of Third-party Obligations” section of Note 6.

(c) We issued performance guarantees and indemnifications for energy trading, International Marine Terminal Pollution Control Bonds and various sale agreements.

(d) As construction agent for third party owners of transmission facilities, we committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Other

Cook Plant

In 2006, during a regular refueling outage, Cook Plant Unit 1 completed the planned replacement of major components, including the reactor vessel head, at a cost of $119 million. These improvements and replacement of major components should increase efficiency as well as adding 40 MW of capacity in the winter. We refueled Cook Plant Unit 2 during March and April 2006 and plan to replace its vessel head during its next refueling outage scheduled for the fall of 2007.

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 with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2005, upon resolution of various contractual matters with Centrica, we received payments from our share in earnings of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In 2006, we received a $70 million payment for our share in earnings of 2005. The 2006 payment is contingent on Centrica’s operating results, contractually capped at $20 million, and, to the extent earned, we expect to receive the 2006 payment in March 2007.

SIGNIFICANT FACTORS

Electric Transmission Texas LLC Joint Venture

In January 2007, we signed a participation agreement with MidAmerican Energy Holdings Company (MidAmerican) to form a joint venture company, Electric Transmission Texas LLC (ETT), to fund, own and operate electric transmission assets in ERCOT. ETT filed with the PUCT in January 2007 requesting regulatory approval to operate as an electric transmission utility in Texas, to transfer from TCC to ETT approximately $76 million of transmission assets currently under construction and to establish a wholesale transmission tariff for ETT. ETT also requested approval from PUCT of initial rates based on an 11.25% return on equity.

Upon receipt of all required regulatory approvals, AEP Utilities, Inc., a subsidiary of AEP, and MEHC Texas Transco LLC, a subsidiary of MidAmerican, each will acquire a 50 percent equity ownership in ETT. AEP and MidAmerican plan for ETT to invest in additional transmission projects in ERCOT. The joint venture partners anticipate in excess of $1 billion in projects could be made by ETT during the next several years.

TCC also made a regulatory filing at the FERC in February 2007 regarding the transfer of certain transmission assets from TCC to ETT. In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone initiative of the Texas legislature. The proposal outlines opportunities for additional significant investment in transmission assets in Texas. The joint venture is anticipated to begin operations in the second half of 2007, subject to regulatory approval from the PUCT and the FERC.

We believe Texas can provide a high degree of regulatory certainty for transmission investment due to the predetermination of ERCOT's need based on reliability needs and significant Texas economic growth as well as public policy that supports "green generation" initiatives, which require transmission access. In addition, a streamlined annual interim transmission cost of service review process is available in ERCOT, which should help reduce regulatory lag. The use of a joint venture structure will allow us to share the capital requirements for this type of significant investment while allowing us to participate in more transmission projects than previously anticipated.

AEP Interstate Project

In January 2006, we filed a proposal with the FERC and PJM to build a new 765 kV 550-mile transmission line from West Virginia to New Jersey. The 765 kV line is designed to reduce PJM congestion costs by substantially improving west-east transfer capability by approximately 5,000 MW during peak loading conditions and reducing transmission line losses by up to 280 MW. The project would also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is approximately $3 billion, of which ownership may ultimately be shared with third party affected participants. The project is subject to PJM, state and FERC approvals of appropriate incentive cost recovery mechanisms. The projected in-service date assumes eight years for siting and construction. Due to delays in approval by the PJM stakeholder process, the projected in-service date is now 2015. This assumes approval by PJM in mid-2007, followed by approval by FERC on initial rates by the end of 2007.

We were the first entity to file with the Department of Energy (DOE) seeking to have the route of a proposed transmission project designated as a National Interest Electric Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. In August 2006, the DOE issued the "National Interest Electric Transmission Congestion Study." In this study, DOE indicated that the mid-Atlantic Coastal area, which the AEP Interstate Project is designed to reinforce, is one of the two most critical congestion areas in the nation. This finding should help us obtain early NIETC Designation as promulgated by the Energy Policy Act of 2005. In October 2006, we filed comments with the DOE encouraging corridor designation that is consistent with the proposed line.

In July 2006, pursuant to our request, the FERC clarified that the project qualifies for incentive rate treatment, provided that the new line is included in PJM's formal Regional Transmission Expansion Plan to be finalized in 2007. The conditionally approved incentives include (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the timely recovery of the cost of capital during the construction period; and (c) the ability to defer and recover costs incurred during the pre-construction and pre-operating period. Since the FERC has clarified that the project qualifies for these rate incentives, we expect to propose rates that will capture the incentives in a future FERC rate filing.

Texas Restructuring

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

TCC will recover its PUCT approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a credit competition transition charge (CTC) rate rider to refund its net regulatory liability for other true-up items.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units.

TCC appealed the PUCT true-up orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections of Note 4.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007 the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final True-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC's nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge's other preliminary determinations that affirm the PUCT's decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management has concluded that it is probable that the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. We cannot estimate the amount at this time, but the amount could exceed TCC's Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

SECA Revenue Subject to Refund

We eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders and implemented SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies have reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. The AEP East companies have provided a reserve for $37 million in net refunds.

We, together with Exelon and the Dayton Power and Light Company, filed an extensive post hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. We believe that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, we believe the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. Although we believe we have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

Virginia Restructuring

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

New Generation

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 629 MW IGCC power plant using clean-coal technology. The application proposed cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs through regulatory authorization until the plant is placed in service. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSPs. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover or refund in distribution rates any difference between the Ohio companies' 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 costs. Through December 31, 2006, the Ohio companies deferred $20 million of pre-construction IGCC costs, of which they have recovered $12 million. The PUCO indicated that if the Ohio companies have not commenced continuous construction of the IGCC plant by 2010, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

In January 2006, APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, West Virginia. In January 2007, the WVPSC issued an order granting APCo's motion to delay the Commission's statutory deadline for issuing an order on the certificate for the construction of the proposed IGCC plant. The WVPSC approved a deadline of December 3, 2007. Through December 31, 2006, APCo deferred pre-construction IGCC costs totaling $10 million.

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation to satisfy the demands of its customers. SWEPCo will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new 600 MW base load coal plant, of which SWEPCo's investment will be 73%, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates for SWEPCo's share of the new facilities are approximately $1.4 billion (this total excludes the related transmission investment and AFUDC). These new facilities are subject to regulatory approvals from SWEPCo's three state commissions. The peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions and Units 3 and 4 are projected to be online in July 2007 and the remaining two units by 2008. Construction is expected to begin in 2007 on the intermediate and base load facilities upon approval from the state regulatory commissions. Expenditures related to construction of these facilities are expected to total $349 million in 2007.

In September 2005, PSO sought proposals for new peaking generation to be online in 2008, and in December 2005 PSO sought proposals for base load generation to be online in 2011. PSO received proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Riverside Station plant in Jenks, Oklahoma where PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Also in March 2006, PSO announced plans to add 170 MW of peaking generation to its Southwestern Station plant in Anadarko, Oklahoma where they will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Combined preliminary cost estimates for these additions are approximately $120 million. In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E) and Oklahoma Municipal Power Authority (OMPA) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. PSO, OG&E and OMPA signed an agreement in February 2007 with Red Rock Power Partners to begin the first phase of the project. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion, and the unit is expected to be online no later than the first half of 2012. These new facilities are subject to regulatory approval from the OCC. Construction of all of these additions is expected to begin in 2007. Expenditures related to construction of these facilities are expected to total $125 million in 2007.

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the second quarter of 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans, collectively the Pension Plans. Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic cost for the Pension Plans and Postretirement Plans:

	2006	2005	2004
Net Periodic Benefit Cost		(in millions)	
Pension Plans	$ 71	$ 61	$ 40
Postretirement Plans	96	109	141
Assumed Rate of Return			
Pension Plans	8.50%	8.75%	8.75%
Postretirement Plans	8.00%	8.37%	8.35%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2006, of approximately 9.43%. We anticipate that the investment managers we employ for the Plans will generate long-term returns averaging 8.50%.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension		Other Postretirement Benefit Plans		
	2006 Actual Asset Allocation	2007 Target Asset Allocation	2006 Actual Asset Allocation	2007 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	63%	65%	66%	65%	10.00%
Real Estate	6%	5%	-%	-%	8.25%
Fixed Income	26%	28%	32%	33%	5.25%
Cash and Cash Equivalents	5%	2%	2%	2%	4.25%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8.50% and 8.00% for the Pension Plans and Postretirement Plans, respectively, are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 12.78% and 7.76% for the twelve-months ended December 31, 2006 and 2005, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2006, we had cumulative gains of approximately $187 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains will result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2006 under this method was 5.75% for the Pension Plans and 5.85% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 8.50%, a discount rate of 5.75% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $40 million, $14 million and $5 million in 2007, 2008 and 2009, respectively. Based on an expected rate of return on the OPEB plans' assets of 8.00%, a discount rate of 5.85% and various other assumptions, we estimate Postretirement Plan costs will approximate $85 million, $81 million and $78 million in 2007, 2008 and 2009, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Management's Financial Discussion and Analysis of Results of Operations.

The value of the Pension Plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005 primarily due to investment returns on the assets. The Qualified Plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of our Postretirement Plans' assets increased to $1.3 billion at December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

Our nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation in excess of plan assets was $78 million and $81 million at December 31, 2006 and 2005, respectively. We made a contribution of $626 million in 2005 to meet our goal of fully funding all Qualified Plans by the end of 2005. Our Qualified Plans remained fully funded as of December 31, 2006.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that our defined benefit pension plans comply with the applicable requirements of such laws.

The Pension Protection Act of 2006 did not materially impact our plans.

Litigation

In the ordinary course of business, we, along with 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 their eventual outcome 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 if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations.

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

Environmental Matters

We are implementing a substantial capital investment program and incurring 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; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants.

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. We are also monitoring possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change. All of these matters are discussed below.

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 described below. The states in which we operate, implement and administer many of these programs and could 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 safety margin. 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 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 submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements 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 affirmed certain aspects of the final CAIR after reconsideration. The rule has been challenged in the courts. States were required to 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.

<u>Hazardous Air Pollutants:</u> 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 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 affirmed certain aspects of the final CAMR after reconsideration, and the rule has been challenged in the courts. States were required to develop and submit their SIPs to implement CAMR by November 2006.

<u>The Acid Rain Program:</u> The 1990 Amendments to the CAA include 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 contain requirements for power plants to reduce NOx 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 continue to 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.

<u>Regional Haze</u>: The CAA 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 of visibility in these areas (the “Regional Haze” program). In 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 CAIR will result in more visibility improvements than BART for power plants subject to it. 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 courts upheld the final rule.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above require us to make significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and are not incorporated into SIPs. As a result, these rules may be further modified. Our estimates 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 and the actual costs to comply could differ significantly from the estimates discussed below.

We installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at our eastern power plants over the past several years to comply with NO_x requirements in various SIPs. We comply with Acid Rain Program SO_2 requirements by installing scrubbers, using alternate fuels and using SO_2 allowances. We receive allowances through Acid Rain Program allocations and purchase them at the annual Federal EPA auction or in the market. Decreasing allowance allocations, our diminishing SO_2 allowance bank and increasing allowance costs will require us to install additional controls on our power plants. In addition under CAIR and CAMR, we will be required to install additional controls by 2010. We plan to install additional scrubbers on 7,300 MW for SO_2 control and additional SCRs on 1,900 MW for NO_x control to comply with current CAIR and CAMR requirements. In January 2007, the scrubber on Unit 2 of Mitchell Plant went into service leaving 6,500 MW of scrubbers to be completed. From 2007 to 2011, we estimate total environmental investment of $2.2 billion including investment in scrubbers and other SO_2 equipment of approximately $1.4 billion. We will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, we expect to incur additional costs for pollution control technology retrofits between 2012 and 2020 of approximately $2.6 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on our units; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

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.

Clean Water Act Regulations

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. Any capital costs incurred to meet these standards had been expected to be incurred between 2008 and 2010. We undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. In addition, a recent court decision introduced additional uncertainty to these costs and their timing.

The rule was challenged in the courts by states, advocacy organizations and industry. On January 25, 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. Among other things, the restoration option, the cost-benefit and other tests and certain alternative technology options in the 2004 rule have been remanded. We cannot predict how or when the Federal EPA will respond to the remand, or what effect the remand may have on similar requirements adopted by the states. We may seek further review or relief from the schedules included in the final rule and our permits, in order to allow time for the Federal EPA's response to the remand.

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 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 1998, but the treaty was not submitted to the Senate for its advice and consent. In 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. Members of

Congress introduced several bills seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none have passed. We participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

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 upheld by an appellate court. The U.S. Supreme Court reviewed the appellate decision and is expected to issue its decision in 2007.

We will seek recovery of expenditures for potential regulation of CO_2 emissions from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions.

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 thereafter against 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 were resolved through consent decrees. The alleged modifications at our power plants occurred over a twenty-year period. A bench trial on the liability issues was held during 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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 were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted 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. The Court denied the Federal EPA’s request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. The Federal EPA also proposed a rule that would define “emissions increases” in a way that would exclude most of the challenged activities from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, 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 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 manage 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

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required: Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We review the probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. In the Arkansas, Louisiana, Oklahoma and Texas jurisdictions, we do not record the fuel portion of unbilled revenue in accordance with the applicable state commission regulatory treatment. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Incremental unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $(19) million, $28 million and $22 million for the years ended December 31, 2006, 2005 and 2004, respectively. Accrued unbilled revenues for the Utility Operations segment were $329 million and $348 million as of December 31, 2006 and 2005, respectively.

Assumptions and Approach Used: The operating company calculates the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required: Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used: We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We base credit adjustments on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used: There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required: In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

<u>Assumptions and Approach Use</u>: The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

<u>Effect if Different Assumptions Used</u>: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 8 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We divested certain noncore assets and their sales values can vary from the recorded fair value as described in Note 8 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

<u>Nature of Estimates Required:</u> We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, "Employers' Accounting For Pensions", SFAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" and SFAS 158. See Note 9 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

<u>Assumptions and Approach Used:</u> The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Expected return on plan assets
- Health care cost trend rate
- Rate of compensation increase
- Cash balance crediting rate

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
		(in millions)		
Effect on December 31, 2006 Benefit Obligations:				
Discount Rate	$ (178.2)	$ 192.7	$ (114.1)	$ 121.4
Compensation Increase Rate	27.2	(25.5)	3.3	(3.2)
Cash Balance Crediting Rate	13.4	16.7	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	91.7	(83.7)
Effect on 2006 Periodic Cost:				
Discount Rate	(13.0)	13.6	(10.4)	10.6
Compensation Increase Rate	5.9	(5.6)	0.6	(0.6)
Cash Balance Crediting Rate	6.7	(1.9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	15.2	(14.7)
Expected Return on Plan Assets	(19.7)	19.7	(5.6)	5.7

N/A = Not Applicable

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, did not materially affect our quarter-over-quarter and year-to-date net income and earnings per share. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used options in limited circumstances totaling 149,000 options in 2004, 10,000 options in 2005 and none during 2006. As of December 31, 2006, we have $90 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 1.64 years. See Note 2 in our Notes to Consolidated Financial Statements for further discussion.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but are unable to quantify the effect at this time. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. We estimate the effect of this interpretation on our financial statements to be an unfavorable adjustment to retained earnings of less than $15 million.

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

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, we may be exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes gas operations which holds forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives, along with physical contracts, which will gradually liquidate and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

In 2006, our Generation and Marketing segment holds power sale contracts to commercial and industrial customers in ERCOT. In 2007, the Generation and Marketing segment will also own wholesale power trading and marketing contracts within ERCOT. The wholesale ERCOT trading and marketing activity was previously reflected in AEP's Utility Operations segment.

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 determined by the commercial operations group in accordance with the market risk policy and monitored by the Chief Risk Officer and risk management staff. When commercial activities exceed predetermined limits, we modify the positions 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 have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive 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 predominantly of 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 embrace 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 on our balance sheet as of December 31, 2006 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2005.

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

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 553	$ 1	$ 94	$ 648	$ 32	$ 680
Noncurrent Assets	260	1	115	376	2	378
Total Assets	813	2	209	1,024	34	1,058
Current Liabilities	(440)	-	(92)	(532)	(9)	(541)
Noncurrent Liabilities	(137)	-	(122)	(259)	(1)	(260)
Total Liabilities	(577)	-	(214)	(791)	(10)	(801)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 236	$ 2	$ (5)	$ 233	$ 24	$ 257

MTM Risk Management Contract Net Assets (Liabilities) Year Ended December 31, 2006 (in millions)

	Utility Operations	Generation and Marketing	All Other	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	(19)	-	13	(6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	1	-	3
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(2)	-	-	(2)
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)	24	1	1	26
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	15	-	-	15
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ 236	$ 2	$ (5)	233
Net Cash Flow and Fair Value Hedge Contracts				24
Ending Net Risk Management Assets at December 31, 2006				$ 257

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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 on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions. Approximately $7 million of the regulatory deferred change is due to the change in the SIA. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

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, to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2006
(in millions)

	2007	2008	2009	2010	2011	After 2011	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (22)	$ 16	$ 2	$ -	$ -	$ -	$ (4)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	142	26	24	-	-	-	192
Prices Based on Models and Other Valuation Methods (b)	(7)	2	15	29	4	5	48
Total	$ 113	$ 44	$ 41	$ 29	$ 4	$ 5	$ 236
Generation and Marketing:							
Prices Actively Quoted – Exchange Traded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1	1	-	-	-	-	2
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ 1	$ 1	$ -	$ -	$ -	$ -	$ 2
All Other:							
Prices Actively Quoted – Exchange Traded Contracts	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(2)	-	-	-	-	-	(2)
Prices Based on Models and Other Valuation Methods (b)	-	(1)	(4)	(3)	1	-	(7)
Total	$ 2	$ (1)	$ (4)	$ (3)	$ 1	$ -	$ (5)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ (18)	$ 16	$ 2	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources – OTC Broker Quotes (a)	141	27	24	-	-	-	192
Prices Based on Models and Other Valuation Methods (b)	(7)	1	11	26	5	5	41
Total	$ 116	$ 44	$ 37	$ 26	$ 5	$ 5	$ 233

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

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	22
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	22
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	36
	Physical Forwards	AEP West	36
	Physical Forwards	West Coast	36
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	36
Coal	Physical Forwards	PRB, NYMEX, CSX	36

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

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

We use 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.

We use forward contracts and collars as cash flow hedges to lock-in prices on certain transactions 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 Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2005 to December 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 cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which 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
Year Ended December 31, 2006
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
Changes in Fair Value	17	(4)	13
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	6	2	8
Ending Balance in AOCI, December 31, 2006	$ 17	$ (23)	$ (6)
After Tax Portion Expected to be Reclassified to Earnings During Next 12-Months	$ 17	$ (2)	$ 15

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 meets 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 December 31, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 3.02%, expressed in terms of net MTM assets and net receivables. As of December 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	$ 851	$ 116	$ 735	1	$ 99
Split Rating	39	14	25	1	25
Noninvestment Grade	17	12	5	2	4
No External Ratings:					
Internal Investment Grade	56	5	51	2	22
Internal Noninvestment Grade	35	14	21	3	19
Total as of December 31, 2006	$ 998	$ 161	$ 837	9	$ 169
Total as of December 31, 2005	$ 1,366	$ 484	$ 882	10	$ 322

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, 2009. 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
December 31, 2006

	2007	2008	2009
Estimated Plant Output Hedged	91%	88%	89%

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 December 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 years ended:

VaR Model

December 31, 2006 (in millions)				December 31, 2005 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$10	$3	$1	$3	$5	$3	$1

The High VaR for 2006 occurred in mid-August during a period of high gas and power volatility. The following day, positions were flattened and the VaR was significantly reduced.

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 $624 million at December 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006. As discussed in Note 17 to the consolidated financial statements, the Company adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 9 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that American Electric Power Company, Inc. and subsidiary companies (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the Company's adoption of new accounting pronouncements in 2004, 2005 and 2006.

/s/Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

AEP management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, the Company's internal control over financial reporting was effective as of December 31, 2006.

AEP's independent registered public accounting firm has issued an attestation report on our assessment of the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in millions, except per-share and share amounts)

	2006	2005	2004
REVENUES			
Utility Operations	$ 12,066	$ 11,157	$ 10,620
Gas Operations	(85)	463	3,068
Other	641	491	557
TOTAL	12,622	12,111	14,245
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,817	3,592	3,059
Purchased Energy for Resale	856	687	670
Purchased Gas for Resale	-	256	2,807
Other Operation and Maintenance	3,639	3,619	3,676
Asset Impairments and Other Related Charges	209	39	-
(Gain) Loss on Disposition of Assets, Net	(69)	(120)	(4)
Depreciation and Amortization	1,467	1,348	1,324
Taxes Other Than Income Taxes	737	763	730
TOTAL	10,656	10,184	12,262
OPERATING INCOME	1,966	1,927	1,983
Interest and Investment Income	99	105	33
Carrying Costs Income	114	55	302
Allowance For Equity Funds Used During Construction	30	21	15
Investment Value Losses	-	(7)	(15)
Gain on Disposition of Equity Investments, Net	3	56	153
INTEREST AND OTHER CHARGES			
Interest Expense	732	697	781
Preferred Stock Dividend Requirements of Subsidiaries	3	7	6
TOTAL	735	704	787
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	1,477	1,453	1,684
Income Tax Expense	485	430	572
Minority Interest Expense	3	4	3
Equity Earnings of Unconsolidated Subsidiaries	3	10	18
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	992	1,029	1,127
DISCONTINUED OPERATIONS, NET OF TAX	10	27	83
EXTRAORDINARY LOSS, NET OF TAX	-	(225)	(121)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(17)	-
NET INCOME	$ 1,002	$ 814	$ 1,089
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	394,219,523	389,969,636	395,622,137
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.52	$ 2.64	$ 2.85
Discontinued Operations, Net of Tax	0.02	0.07	0.21
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)
Cumulative Effect of Accounting Change, Net of Tax	-	(0.04)	-
TOTAL BASIC EARNINGS PER SHARE	$ 2.54	$ 2.09	$ 2.75
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	396,483,464	391,423,842	396,590,407
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.50	$ 2.63	$ 2.85
Discontinued Operations, Net of Tax	0.03	0.07	0.21
Extraordinary Loss, Net of Tax	-	(0.58)	(0.31)
Cumulative Effect of Accounting Change, Net of Tax	-	(0.04)	-
TOTAL DILUTED EARNINGS PER SHARE	$ 2.53	$ 2.08	$ 2.75
CASH DIVIDENDS PAID PER SHARE	$ 1.50	$ 1.42	$ 1.40

See Notes to Consolidated Financial Statements.

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

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 301	$ 401
Other Temporary Cash Investments	425	127
Accounts Receivable:		
Customers	676	826
Accrued Unbilled Revenues	350	374
Miscellaneous	44	51
Allowance for Uncollectible Accounts	(30)	(31)
Total Accounts Receivable	1,040	1,220
Fuel, Materials and Supplies	913	726
Risk Management Assets	680	926
Regulatory Asset for Under-Recovered Fuel Costs	38	197
Margin Deposits	120	221
Prepayments and Other	71	127
TOTAL	3,588	3,945
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,787	16,506
Transmission	7,018	6,433
Distribution	11,338	10,702
Other (including coal mining and nuclear fuel)	3,405	3,263
Construction Work in Progress	3,473	2,217
Total	42,021	39,121
Accumulated Depreciation and Amortization	15,240	14,837
TOTAL - NET	26,781	24,284
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,477	3,262
Securitized Transition Assets	2,158	593
Spent Nuclear Fuel and Decommissioning Trusts	1,248	1,134
Goodwill	76	76
Long-term Risk Management Assets	378	886
Employee Benefits and Pension Assets	327	1,105
Deferred Charges and Other	910	843
TOTAL	7,574	7,899
Assets Held for Sale	44	44
TOTAL ASSETS	$ 37,987	$ 36,172

See Notes to Consolidated Financial Statements.

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

	2006	2005
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,360	$ 1,144
Short-term Debt	18	10
Long-term Debt Due Within One Year	1,269	1,153
Risk Management Liabilities	541	906
Customer Deposits	339	571
Accrued Taxes	781	651
Accrued Interest	186	183
Other	962	842
TOTAL	5,456	5,460
NONCURRENT LIABILITIES		
Long-term Debt	12,429	11,073
Long-term Risk Management Liabilities	260	723
Deferred Income Taxes	4,690	4,810
Regulatory Liabilities and Deferred Investment Tax Credits	2,910	2,747
Asset Retirement Obligations	1,023	936
Employee Benefits and Pension Obligations	823	355
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	148	157
Deferred Credits and Other	775	762
TOTAL	23,058	21,563
TOTAL LIABILITIES	28,514	27,023
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2006	2005
Shares Authorized	600,000,000	600,000,000
Shares Issued	418,174,728	415,218,830

	2006	2005
(21,499,992 shares were held in treasury at December 31, 2006 and 2005, respectively)	2,718	2,699
Paid-in Capital	4,221	4,131
Retained Earnings	2,696	2,285
Accumulated Other Comprehensive Income (Loss)	(223)	(27)
TOTAL	9,412	9,088
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 37,987	$ 36,172

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in millions)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 1,002	$ 814	$ 1,089
Less: Discontinued Operations, Net of Tax	(10)	(27)	(83)
Income Before Discontinued Operations	992	787	1,006
Adjustments for Noncash Items:			
Depreciation and Amortization	1,467	1,348	1,324
Deferred Income Taxes	24	65	291
Deferred Investment Tax Credits	(29)	(32)	(29)
Cumulative Effect of Accounting Changes, Net	-	17	-
Extraordinary Loss	-	225	121
Asset Impairments, Investment Value Losses and Other Related Charges	209	46	15
Carrying Costs Income	(114)	(55)	(302)
Gain on Sales of Assets and Equity Investments, Net	(72)	(176)	(157)
Amortization of Nuclear Fuel	50	56	52
Mark-to-Market of Risk Management Contracts	(37)	84	14
Pension Contributions to Qualified Plan Trusts	-	(626)	(231)
Fuel Over/Under-Recovery, Net	182	(239)	96
Deferred Property Taxes	(14)	(17)	(3)
Change in Other Noncurrent Assets	(15)	(115)	(176)
Change in Other Noncurrent Liabilities	28	67	260
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	177	(7)	280
Fuel, Materials and Supplies	(187)	(20)	33
Margin Deposits	101	(108)	6
Accounts Payable	56	140	(306)
Accrued Taxes	128	48	427
Customer Deposits	(232)	157	35
Other Current Assets	17	52	(53)
Other Current Liabilities	1	180	8
Net Cash Flows From Operating Activities	2,732	1,877	2,711
INVESTING ACTIVITIES			
Construction Expenditures	(3,528)	(2,404)	(1,637)
Change in Other Temporary Cash Investments, Net	(33)	76	32
Investment in Discontinued Operations, Net	-	-	(59)
Purchases of Investment Securities	(18,359)	(8,836)	(1,574)
Sales of Investment Securities	18,080	8,934	1,620
Acquisitions of Assets	-	(360)	-
Proceeds from Sales of Assets	186	1,606	1,357
Other	(89)	(21)	(68)
Net Cash Flows Used For Investing Activities	(3,743)	(1,005)	(329)
FINANCING ACTIVITIES			
Issuance of Common Stock	99	402	17
Repurchase of Common Stock	-	(427)	-
Change in Short-term Debt, Net	7	(13)	(409)
Issuance of Long-term Debt	3,359	2,651	682
Retirement of Long-term Debt	(1,946)	(2,729)	(2,511)
Dividends Paid on Common Stock	(591)	(553)	(555)
Other	(17)	(122)	(64)
Net Cash Flows From (Used For) Financing Activities	911	(791)	(2,840)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	81	(458)
Cash and Cash Equivalents at Beginning of Period	401	320	778
Cash and Cash Equivalents at End of Period	$ 301	$ 401	$ 320
CASH FLOWS FROM DISCONTINUED OPERATIONS			
Operating Activities	$ -	$ -	$ (3)
Investing Activities	-	-	(10)
Financing Activities	-	-	-
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	-	-	(13)
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	-	13
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ -	$ -

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005, and 2004
(in millions)

	Common Stock					
	Shares	**Amount**	**Paid-in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total**
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	6	11			17
Common Stock Dividends				(555)		(555)
Other			8			8
TOTAL						7,344
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(104)	(104)
Cash Flow Hedges, Net of Tax of $51					94	94
Minimum Pension Liability, Net of Tax of $52					92	92
NET INCOME				1,089		1,089
TOTAL COMPREHENSIVE INCOME						1,171
DECEMBER 31, 2004	405	2,632	4,203	2,024	(344)	8,515
Issuance of Common Stock	10	67	335			402
Common Stock Dividends				(553)		(553)
Repurchase of Common Stock			(427)			(427)
Other			20			20
TOTAL						7,957
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(6)	(6)
Cash Flow Hedges, Net of Tax of $15					(27)	(27)
Securities Available for Sale, Net of Tax of $11					20	20
Minimum Pension Liability, Net of Tax of $175					330	330
NET INCOME				814		814
TOTAL COMPREHENSIVE INCOME						1,131
DECEMBER 31, 2005	415	2,699	4,131	2,285	(27)	9,088
Issuance of Common Stock	3	19	80			99
Common Stock Dividends				(591)		(591)
Other			10			10
TOTAL						8,606
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $11					21	21
Securities Available for Sale, Net of Tax of $0					(1)	(1)
Minimum Pension Liability, Net of Tax of $1					2	2
NET INCOME				1,002		1,002
TOTAL COMPREHENSIVE INCOME						1,024
Minimum Pension Liability Elimination, Net of Tax of $9					17	17
SFAS 158 Adoption, Net of Tax of $126					(235)	(235)
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC and TNC are completing the final stage of exiting the generation business. WPCo and KGPCo provide only transmission and distribution services. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated independent power and cogeneration facilities, coal mining and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP, AEPSC and its other subsidiaries are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA). AEP's public utility subsidiaries are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The state regulatory commissions with jurisdiction approve the rates charged and regulate the services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services. The FERC also regulates certain, mostly affiliated, transactions under the 2005 PUHCA.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based and are not cost-based regulated unless we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region in which the transaction is taking place. We have wholesale power supply contracts with various municipalities and cooperatives that are FERC regulated, cost-based contracts and our wholesale power transactions in the SPP region are all cost-based due to our having market power in the SPP region as determined by the FERC. As of December 31, 2006, only SWEPCo, PSO and TNC operate in the SPP region.

The FERC also regulates, on a cost basis, our wholesale transmission service and rates except in Texas. The FERC has claimed jurisdiction over retail transmission rates when the retail rates are unbundled in connection with restructuring. In Ohio, CSPCo's and OPCo's rates are unbundled, therefore our retail transmission rates are based on FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although our retail rates are unbundled in Virginia and Texas, retail transmission rates are still regulated, on a cost basis, by the state regulatory commissions.

In addition, FERC regulates our East and West Power Pools, East Transmission Equalization Agreement, System Interim Allowance Agreement, and SIA, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to the agreements.

The state regulatory commissions regulate all of our retail public utility operations (generation, transmission and distribution operations) and rates except in states that have enacted restructuring legislation where only transmission and distribution rates are regulated on a cost-basis and unbundled by function. Our retail generation/power supply operations and rates are cost-based regulated by the state regulatory commissions except for CSPCo and OPCo in Ohio and APCo in Virginia, which are in transition to market pricing under state restructuring legislation. However, Virginia legislature adopted amendments to its electric restructuring law. If approved, Virginia would return to a form of cost-based regulation. AEP has no Texas jurisdictional retail generation/power supply operations in Texas other than a minor generational supply operation through a commercial and industrial customer REP. See Note 4 for further details of such legislation and its effects on AEP in Ohio, Texas, Virginia and Michigan.

In 2004 and 2005, we were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated predominantly at cost. Jurisdiction over holding company-related activities has been transferred to the FERC. Regulation and required reporting under the 2005 PUHCA have been reduced compared to the 1935 PUHCA. However, the FERC has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, intercompany transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

Both FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially-controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) “Consolidation of Variable Interest Entities” (FIN 46R) (see “Guarantees of Third-Party Obligations” section of Note 6). We also have generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required transitions to customer choice and market-based rates, we discontinued the application of SFAS 71, regulatory accounting, for the generation portion of our business: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and in Texas for TCC, TNC and the Texas portion of SWEPCo in September 1999. SFAS 101, “Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71” requires the recognition of an impairment of stranded regulatory assets and stranded plant costs if they are not recoverable in regulated rates. Such impairments arising from the discontinuance of SFAS 71 are classified as an extraordinary item. TCC recorded extraordinary impairment losses related to its regulatory assets and plant costs in 2004 and 2005 resulting from the discontinuance of cost-based regulation of their generation business without full recovery of the resultant stranded costs.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management’s evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations including domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three-months or less.

Other Temporary Cash Investments

Other Temporary Cash Investments include marketable securities that we intend to hold for less than one year and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Cash Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities reflected in Other Temporary Cash Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

The following is a summary of Other Temporary Cash Investments at December 31:

Other Temporary Cash Investments	2006 Cost	2006 Gross Unrealized Gains	2006 Gross Unrealized Losses	2006 Estimated Fair Value	2005 Cost	2005 Gross Unrealized Gains	2005 Gross Unrealized Losses	2005 Estimated Fair Value
				(in millions)				
Cash (a)	$ 138	$ -	$ -	$ 138	$ 96	$ -	$ -	$ 96
Government Debt Securities	258	-	-	258	-	-	-	-
Corporate Equity Securities	1	28	-	29	2	29	-	31
Total Other Temporary Cash Investments	$ 397	$ 28	$ -	$ 425	$ 98	$ 29	$ -	$ 127

(a) Primarily represents amounts held for the payment of debt.

Proceeds from sales of current available-for-sale securities were $17,449 million, $8,228 million and $670 million in 2006, 2005 and 2004, respectively. Purchases of current available-for-sale securities were $17,667 million, $8,075 million and $573 million in 2006, 2005 and 2004, respectively. Gross realized gains from the sale of current available-for-sale securities were $39 million and $47 million in 2006 and 2005, respectively, and were not material in 2004. Gross realized losses from the sale of current available-for-sale securities were not material in 2006, 2005 or 2004.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2006 is as follows:

Maturity	Fair Value (in millions)
2007	$ -
2008 – 2011	-
2012 – 2016	4
After 2016	254
Total	$ 258

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables – AEP Credit" section of Note 15).

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. that are included in our consolidated financial statements and investments outside the U.S. that are accounted for under the equity method are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52, "Foreign Currency Translation." In 2006, we completed the disposal of our various non-U.S. equity method investments. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year, unless a specific rate can be identified through an event. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The foreign currency translation balance of Accumulated Other Comprehensive Income (Loss) as of December 31, 2006 and 2005 was $58 thousand and $53 thousand, respectively, and was reduced primarily due to the disposition of our U.K. assets in 2004, which is reflected in Discontinued Operations on our Consolidated Statements of Income.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit our fuel cost calculations. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia (prior to July 2006) and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, Michigan for I&M, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO, Virginia and West Virginia (beginning July 1, 2006) for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky, West Virginia (beginning July 1, 2006) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana and prior to July 1, 2006 in West Virginia), where fuel clauses have been capped, frozen or suspended for a period of years, fuel costs impact earnings. The Indiana fuel clause suspension ends June 30, 2007. In West Virginia, deferred fuel accounting for over- or under-recovery began July 1, 2006. Changes in fuel costs also impact earnings for certain of our IPP generating units that do not have long-term contracts for their fuel supply or have not hedged fuel costs.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

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

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase-and-sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, prior to settlement, we recognize as Revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period. If the contract results in the physical delivery of power, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy for Resale. If the contract does not physically deliver, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues on our Consolidated Statements of Income on a net basis (see "Derivatives and Hedging" section of Note 12).

Domestic Gas Pipeline and Storage Activities

As a result of the sale of HPL in 2005, our domestic gas pipeline and storage activities ceased. Prior to the sale of HPL, we recognized revenues from domestic gas pipeline and storage services when gas was delivered to contractual meter points or when services were provided, with the exception of certain physical forward gas purchase-and-sale contracts that were derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues on our Consolidated Statements of Income. The unrealized and realized gains and losses on physically-settled resale gas contracts for the purchase of natural gas are presented as Purchased Gas for Resale on our Consolidated Statements of Income (see "Fair Value Hedging Strategies" section of Note 12).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options and over-the-counter options and swaps.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow or fair value hedge relationship, or as a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge) or as hedges of a recognized asset, liability or firm commitment (fair value hedge). We recognize the gains or losses on derivatives designated as fair value hedges in Revenues on our Consolidated Statements of Income in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, we initially record the effective portion of the derivative's gain or loss as a component of Accumulated Other Comprehensive Income (Loss) and, depending upon the specific nature of the risk being hedged, subsequently reclassify into Revenues or fuel expenses on our Consolidated Statements of Income when the forecasted transaction is realized and affects earnings. We recognize the ineffective portion of the gain or loss in Revenues on our Consolidated Statements of Income immediately, except in those jurisdictions subject to cost-based regulation. In those regulated jurisdictions we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" sections of Note 12).

Barging Activities

MEMCO Operations revenue is recognized based on percentage of completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by MEMCO's computerized barge tracking system. The recognition of revenue based upon the percentage of voyage completion results in a better matching of revenue and expenses.

Construction Projects for Outside Parties

We engage in construction projects for outside parties and account for the projects on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as we incur and bill project costs to the outside party.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer maintenance costs during refueling outages at the Cook Plant and amortize the costs over the period between outages in accordance with rate orders in Indiana and Michigan.

Income Taxes and Investment Tax Credits

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

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

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series. We credit the excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize purchased goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for all allowances. We record allowances expected to be consumed within one year in Fuel, Materials and Supplies and allowances with expected consumption beyond one year in Other Noncurrent Assets-Other on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of the applicable company or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust funds for each regulatory jurisdiction, which are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Upon the issuance of FSP 115-1 and 124-1 “The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments,” we consider all nuclear decommissioning trust fund and spent nuclear fuel trust fund investments in unrealized loss positions to be other-than-temporary impairments as we do not make specific investment decisions regarding assets held in trusts. Thus, effective in 2006, the other-than-temporary impairments are considered realized losses and will reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. Amounts prior to 2006 were not restated as the other-than-temporary impairments do not affect earnings or AOCI. We record unrealized gains and losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 10 for additional discussion of nuclear matters.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the 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	December 31, 2006	December 31, 2005
	(in millions)	
Securities Available for Sale, Net of Tax	$ 18	$ 19
Cash Flow Hedges, Net of Tax	(6)	(27)
Minimum Pension Liability, Net of Tax (a)	-	(19)
SFAS 158 Adoption, Net of Tax (a)	(235)	-
Total	$ (223)	$ (27)

(a) See “SFAS 158, Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans” section of Note 2.

At December 31, 2006, we expect to reclassify approximately $15 million of net gains from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve-months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations.

At December 31, 2006, forty-two-months is the maximum length of time that our exposure to variability in future cash flows is hedged with contracts designated as cash flow hedges.

Stock-Based Compensation Plans

As of December 31, 2006, we had stock options, performance units, restricted shares and restricted stock units outstanding to employees under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was originally approved by shareholder vote in 2000 and the Amended and Restated version was subsequently approved in 2005.

We maintain career share accounts under the Stock Ownership Requirement Plan to facilitate executives in meeting minimum stock ownership requirements assigned to executives by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends.

We also compensate our non-employee directors, in part, with stock units under The Stock Unit Accumulation Plan for Non-Employee Directors. These stock units also do not become payable in cash to Directors until after their service to the company ends.

In addition, we maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP stock.

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 (SFAS 123R)" 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 for awards with service only conditions from the accelerated multiple-option approach to the straight-line single-option method. We recognize compensation expense for all share-based payment awards granted prior to January 1, 2006 using the accelerated multiple-option approach while we recognize compensation expense for all share-based payment awards with service only condition granted on or after January 1, 2006 using the straight-line single-option method. In 2006, we granted an award with performance conditions which continue to be expensed on the accelerated multiple-option approach. As stock-based compensation expense recognized on our Consolidated Statements of Income for the year ended December 31, 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 in Note 16 as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the years ended December 31, 2005 and 2004, 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. For the years ended December 31, 2006, 2005 and 2004, 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 16 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 years ended December 31, 2005 and 2004:

	2005	2004
	(in millions, except per share data)	
Net Income, as reported	$ 814	$ 1,089
Add: Stock-based compensation expense included in reported Net Income, net of related tax effects	22	15
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(22)	(18)
Pro Forma Net Income	$ 814	$ 1,086
Earnings Per Share:		
Basic – as Reported	$ 2.09	$ 2.75
Basic – Pro Forma (a)	$ 2.09	$ 2.74
Diluted – as Reported	$ 2.08	$ 2.75
Diluted – Pro Forma (a)	$ 2.08	$ 2.74

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

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

	2006		2005		2004	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Applicable to Common Stock	$ 1,002		$ 814		$ 1,089	
Average Number of Basic Shares Outstanding	394.2	$ 2.54	390.0	$ 2.09	395.6	$ 2.75
Average Dilutive Effect of:						
Performance Share Units	1.8	0.01	1.0	0.01	0.6	-
Stock Options	0.3	-	0.3	-	0.3	-
Restricted Stock Units	0.1	-	-	-	-	-
Restricted Shares	0.1	-	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	396.5	$ 2.53	391.4	$ 2.08	396.6	$ 2.75

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share.

Options to purchase 0.4 million, 0.5 million and 5.2 million shares of common stock were outstanding at December 31, 2006, 2005 and 2004, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

Supplementary Information

Related Party Transactions		2006		2005		2004
			Year Ended December 31,			
			(in millions)			
AEP Consolidated Purchased Energy:						
Ohio Valley Electric Corporation (43.47% Owned)	$	223	$	196	$	161
Sweeny Cogeneration Limited Partnership (50% Owned)		121		141		-
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)		28		20		14
AEP Consolidated Revenues – Utility Operations:						
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)		(37)		-		-
Cash Flow Information						
Cash paid (received) for:						
Interest, Net of Capitalized Amounts		664		637		755
Income Taxes, Net of Refunds		358		439		(107)
Noncash Investing and Financing Activities:						
Acquisitions Under Capital Leases		106		63		123
Disposition of Liabilities Related to Acquisitions/Divestitures, Net		-		(18)		(67)
Noncash Construction Expenditures Included in Accounts Payable at December 31		404		253		116
Noncash Acquisition of Nuclear Fuel in Accounts Payable at December 31		-		24		-

Power Projects

We own a 50% interest in Sweeny, a domestic unregulated power plant with a capacity of 480 MW located in Texas. In 2006, we sold our 50% interest in an international power plant totaling 600 MW located in Mexico (see "Dispositions" section of Note 8).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Deferred Charges and Other on our Consolidated Balance Sheets. At December 31, 2006 and 2005, the 50% owned domestic power project and international power investment are accounted for under the equity method and have unrelated third-party partners. The domestic project is a combined cycle gas turbine that provides steam to a host commercial customer and is considered a Qualifying Facility (QF) under PURPA. The international power investment was classified as a Foreign Utility Company (FUCO) under the Energy Policies Act of 1992.

The domestic power project has project-level financing, which is nonrecourse to AEP.

Reclassifications

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

On our Consolidated Balance Sheets, we reclassified $147 million of mining equipment as of December 31, 2005 from Production to Other within Property, Plant and Equipment.

On our Consolidated Statements of Income, we reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. These reclassifications totaled $30 million and $24 million for 2005 and 2004, respectively.

In our segment information, we reclassified two subsidiary companies, AEP Texas Commercial & Industrial Retail GP, LLC and AEP Texas Commercial & Industrial Retail LP, from the Utility Operations segment to the Generation and Marketing segment as discussed in Note 11. Combined revenues for these companies totaled $36 million and $44 million for 2005 and 2004, respectively. As a result, on our Consolidated Statements of Income we reclassified these revenues from Utility Operations to Other.

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

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

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 final pronouncements that we have determined relate to our operations.

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

The FASB issued SFAS 123R, requiring 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.

In 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 FASB Staff Positions (FSP) that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R in 2006. We adopted SFAS 123R using the modified prospective method without materially affecting our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In 2005, the FASB issued SFAS 154. The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. It requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. It also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 was effective for accounting changes and corrections of errors after January 1, 2006 and is applied as necessary.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption.

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but we are unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

SFAS 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"

In September 2006, the FASB issued SFAS 158, amending previous standards. It requires employers to fully recognize the obligations associated with defined benefit pension plans and other postretirement employee benefit (OPEB) plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions), and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year.

The effect of SFAS 158 is to adjust pretax AOCI at the end of each year, for both underfunded deferred benefit and overfunded pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates. Favorable changes include higher returns that increase plan assets and higher discount rates that reduce the discounted benefit obligation.

We adopted SFAS 158 as of December 31, 2006. We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery. The following table shows the incremental effect of this standard on our financial statements versus prior accounting requirements including the additional minimum pension liability provisions of SFAS 87, "Employers' Accounting for Pensions," which were replaced by SFAS 158 as follows:

	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
		(in millions)	
Prepaid Benefit Costs	$ 1,038	$ (718)	$ 320
Current Accrued Benefit Liability	-	(13)	(13)
Noncurrent Accrued Benefit Liability	(80)	(505)	(585)
Regulatory Assets	-	875	875
Deferred Income Taxes	9	117	126
Additional Minimum Liability	(32)	32	N/A
Intangible Asset	6	(6)	N/A
Net of Tax AOCI Equity Reduction	17	218	235
Total	$ 958	$ -	$ 958

N/A = Not Applicable

SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities.

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48)

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. Although we are in the process of evaluating the impact of FIN 48, we estimate the effect of this interpretation on our financial statements to be an unfavorable adjustment to retained earnings of less than $15 million.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Purchases or sales of inventory transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions," if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. We implemented this issue beginning April 1, 2006 without a material impact on our financial statements.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed. The EITF's decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

As disclosed in Note 1, we act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. Our policy is to present these taxes on a net basis. We do not recognize these taxes as revenues or expenses. Therefore, this issue did not impact our financial statements.

SAB No. 108 "Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements" (SAB 108)

In September 2006, the SEC staff issued SAB 108 addressing diversity in practice when quantifying the effect of an error on financial statements. It provides guidance on the consideration of the effects of prior year misstatements in quantifying misstatements in current year financial statements. Our adoption of SAB 108, effective December 31, 2006, did not have a material impact 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 business combinations, revenue recognition, liabilities and equity, derivatives disclosures, earnings per share calculations, leases, insurance, 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.

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in Extraordinary Loss, Net of Tax on our 2005 Consolidated Statement of Income (see " TCC Texas Restructuring" section of Note 4).

In 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. We recorded this adjustment as an extraordinary item in accordance with SFAS 101. The adjustment is included in Extraordinary Loss, Net of Tax on our 2004 Consolidated Statement of Income.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Asset Retirement Obligations

In 2005, we recorded a $26 million ($17 million, net of tax) cumulative effect of accounting change for ARO in accordance with FIN 47 in the Utility Operations segment. This adjustment is included in Cumulative Effect of Accounting Change, Net on our 2005 Consolidated Statement of Income.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2006 and 2005 by operating segment are as follows:

	Utility Operations	MEMCO Operations	AEP Consolidated
		(in millions)	
Balance at January 1, 2005	$ 37.1	$ 38.8	$ 75.9
Impairment Losses	-	-	-
Balance at December 31, 2005	37.1	38.8	75.9
Impairment Losses	-	-	-
Balance at December 31, 2006	$ 37.1	$ 38.8	$ 75.9

In the fourth quarters of 2005 and 2006, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses required.

Other Intangible Assets

Acquired intangible assets subject to amortization were $19.4 million at December 31, 2006 and $23.9 million at December 31, 2005, net of accumulated amortization and are included in Deferred Charges and Other on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31, 2006		December 31, 2005	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Patent	5	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Easements	10	2.2	1.1	2.2	0.7
Purchased Technology	10	10.9	5.4	10.9	4.3
Advanced Royalties	10	29.4	16.6	29.4	13.6
Total		$ 42.6	$ 23.2	$ 42.6	$ 18.7

Amortization of intangible assets was $5 million, $4 million and $4 million for 2006, 2005 and 2004, respectively. Our estimated total amortization is $5 million for 2007, $4 million per year for 2008 through 2010 and $2 million in 2011, when all assets will be fully amortized with no residual value.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. This note is a discussion of pending rate matters, including industry restructuring and customer choice related proceedings, that could materially impact results of operations and cash flows.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

Ohio restructuring legislation provided for a transition to market pricing for power supply beginning on January 1, 2006. Open access to power suppliers began in Ohio on January 1, 2001 with a five-year transition to market pricing. Under a 2000 PUCO-approved settlement agreement, CSPCo and OPCo (the Ohio companies) froze their rates through December 31, 2005. In accordance with the approved settlement agreement, CSPCo and OPCo amortize their stranded generation-related transition regulatory assets commensurate with recovery through their frozen rates and starting January 1, 2006 through rate riders that expire in 2008 and 2007, respectively. To date, CSPCo and OPCo have lost very few customers to competing suppliers.

In 2005, the PUCO approved Rate Stabilization Plans (RSPs) for the Ohio companies effective January 1, 2006 and ending December 31, 2008, which allow the Ohio companies to increase their generation rates over three years. The approved three-year RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7% a year, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year to recover governmentally-mandated costs. During 2006 through 2008, the RSPs also allow the Ohio companies to recover regulatory assets for 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs, net of financial transmission rights (FTR) revenues, related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program.

Pretax earnings increased by $110 million for the Ohio companies in 2006 from the RSP rate increases, net of the amortization of RSP regulatory assets. This increase includes the recovery of unrecognized equity carrying costs for 2004 and 2005. At December 31, 2006, unrecognized equity costs total $29 million. As of December 31, 2006, the unamortized RSP regulatory assets to be recovered through December 31, 2008 were $38 million.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court challenging the RSPs and also arguing that there is no POLR obligation the Ohio companies are entitled to recover. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies and remanded the case to the PUCO for further proceedings. In August 2006, the PUCO acted on the Ohio companies' remand case ordering them to file a plan to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective. Accordingly, the Ohio companies continue collecting RSP revenues, amortizing the RSP costs and realizing and recognizing related equity carrying costs.

In September 2006, the Ohio companies submitted their proposal to the PUCO to provide additional options for customer participation in the electric market. The proposal provides for the recovery of the cost of providing the additional options. In January 2007, the PUCO set a schedule for interested persons to file comments concerning the proposal.

The Ohio Supreme Court did not address any other issues raised on appeal, stating its decision did not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. Management believes that the RSP regulatory assets remain probable of recovery and that the Ohio companies will continue to collect RSP revenues.

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs.

CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans. At this time, management is unable to predict whether the Ohio companies will transition to market pricing, whether the RSP will be extended with or without modification, or whether cost-based regulation will be reinstated on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals

As provided in the restructuring settlement agreement approved by the PUCO in 2000, the Ohio companies established regulatory assets for customer choice implementation costs and related carrying costs in excess of $40 million in total for recovery in the next general rate filing to change distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next distribution rate filing to change rates after the end of the RSP period dated December 31, 2008. Through December 31, 2006, we incurred $99 million of such costs and established regulatory assets of $49 million for such costs. We have not recognized $10 million of equity carrying costs, which are not recognizable until collected. 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.

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 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent 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 costs. 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 under their RSPs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through December 31, 2006, the Ohio companies recorded pre-construction IGCC regulatory assets of $20 million and recovered $12 million of those costs. We are currently recovering the remaining amounts through June 30, 2007. In its June order, the PUCO indicated that if the

Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest. 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.

In August 2006, The Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, the Ohio companies could be required to refund Phase I cost-related recoveries.

Transmission Rate Filing

In accordance with the RSPs, in December 2005, the PUCO approved the recovery of certain RTO transmission costs through separate transmission cost recovery riders for the Ohio companies. The transmission cost recovery riders are subject to an annual true-up process. In May 2006, the PUCO issued an order approving a two-step increase in the transmission cost recovery riders effective April 1, 2006. The Ohio companies implemented the new tariffs in June 2006. They reflect the Ohio companies' share of the loss of SECA revenues in step one. The step two increase, effective August 1, 2006, reflects the change in the AEP East Zone transmission rate approved by the FERC related to completion of the new Wyoming-Jacksons Ferry 765 kV line.

In October 2006, the Ohio companies filed for initial true-ups under the transmission cost recovery riders. The filings reflect the refund of a regulatory liability, as of September 30, 2006, of $12 million and $16 million for CSPCo and OPCo, respectively, including carrying charges. These refunds were reflected as part of new transmission cost recovery riders, which became effective for 2007. The net effect of the new transmission cost recovery riders is to increase cost recoveries in 2006 over 2005 levels for CSPCo and OPCo by $27 million and $36 million, respectively. We anticipate a favorable net effect in 2007 over 2005 levels of $15 million and $18 million, respectively.

Distribution Service Reliability and Restoration Costs

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 for the Ohio companies to meet. In July 2006, based on a staff report on service reliability and responses filed by the Ohio companies, the PUCO directed the Ohio companies to earmark $10 million for future measures to improve service reliability without recovery. The PUCO further indicated that it will determine where and how to expend the $10 million.

The Ohio companies implemented storm cost recovery riders effective with September 2006 billings, to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. The riders will continue until they have collected the authorized amounts or one year, whichever is shorter.

As a result, at December 31, 2006 the Ohio companies have regulatory assets of $7 million for these costs.

Distribution Reliability Plan

In January 2006, the Ohio companies initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, the Ohio companies filed a proposed enhanced reliability plan. The plan contemplates recovering approximately $71 million in additional distribution revenue during an eighteen-month period beginning July 2007. A hearing is scheduled for April 2007. The OCC filed testimony, which argues that the Ohio companies should be required to improve their distribution service reliability with funds from their existing rates. Management is unable to predict the outcome of this proceeding.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by the Ohio companies of the difference between $43 per MWH to be paid by Ormet for power and a market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, the Ohio companies submitted a market price of $47.69 per MWH, which is pending PUCO approval.

Texas Rate Matters

TCC TEXAS RESTRUCTURING

TCC's True-up Proceedings and 2002 Securitization

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation-related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

In 2002, TCC securitized $797 million to recover most of its stranded generation related regulatory assets. TCC sold its generating units to establish its stranded costs and recorded an impairment loss, which resulted in an additional net true-up regulatory asset recoverable under the Texas Restructuring Legislation. Beginning in 2002, TCC also recorded wholesale capacity auction true-up revenues and debt-related carrying costs on its net true-up regulatory asset, as additional true-up regulatory assets. Unrecognized equity carrying costs of $224 million included in the net stranded generation cost to be securitized will be recognized, as collected through transition charge securitization revenues, over the fourteen-year term of the securitization bonds.

In December 2004, predominately based on a PUCT disallowance of a specific stranded cost item in other true-up proceedings, TCC reduced its true-up regulatory assets.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units. Based on the PUCT's order in December 2005, TCC reduced its true-up regulatory asset. The order also identified a reduction in the net recoverable amount, which represented the present value benefit of ADITC and EDFIT related to the plants sold. See "TCC's 2006 CTC Proceeding" section below.

TCC will recover its PUCT-approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a competition transition charge (CTC) rate rider credit to refund its net regulatory liability for other true-up items.

TCC's 2006 Securitization Proceeding

TCC filed an application in March 2006 requesting recovery through the issuance of securitization bonds of $1.804 billion of PUCT-approved securitizable net stranded generation costs plus subsequent carrying costs through August 31, 2006 and issuance costs. The securitization request excluded TCC's net regulatory liability for other true-up items, which will be refunded to customers using a CTC rate rider. See the "TCC's 2006 CTC Proceeding" section of this note. The PUCT approved a settlement in June 2006, which reduced the securitizable amount by $77 million and settled several issues and authorized the issuance of securitization bonds of $1.72 billion as of August 31, 2006. TCC issued securitization bonds on October 11, 2006 for $1.74 billion, which included additional issuance and carrying costs through October 11, 2006.

The securitization order provides for TCC to recover the securitization bond principal and related interest expense from customers over the fourteen-year term of the securitization bonds. Beginning in October 2006, the Securitized Transition Asset is amortized based on the ratio of annual transition revenues to total revenues over the fourteen-year TC collection period.

The June 2006 securitization order reduced the amount to be securitized and recovered by the present value of the ADITC and EDFIT benefit identified above in the April 2006 final true-up order. The securitization order also identified the present value cost-of-money benefit generated through the final year the securitization bonds will be outstanding (fourteen years) as an additional reduction. The present value cost-of-money benefit of $315 million resulted from the ADFIT related to the generation assets. However, rather than reducing the amount to be securitized, the PUCT ordered TCC to refund the ADFIT benefit through the CTC rate rider credit. See the "TCC's 2006 CTC Proceeding" section below for further details.

TCC's 2006 CTC Proceeding

In June 2006, TCC filed to refund, through a CTC rate rider credit, its net other true-up items and the ADFIT cost-of-money benefit less the present value benefit of ADITC and EDFIT, discussed above. An interim order required that the CTC refund begin in October 2006 pending a final CTC decision. The PUCT issued a final order in December 2006, which required that TCC refund $356 million of other true-up items and $19 million in estimated interest through the CTC over twenty-one months starting in October 2006. The ADFIT cost-of-money benefit of $315 million has a retrospective portion of $75 million which has been expensed and a prospective portion of $240 million which will be amortized to expense over the fourteen-year securitization bond term consistent with the period over which the cost-of-money benefit is generated and computed in the securitization order. The difference between the amount being refunded and the net other true-up regulatory liability of $219 million ($155 million at December 31, 2006) is predominantly due to the inclusion in the CTC refund of the $240 million unrecorded prospective portion of the ADFIT cost-of-money benefit less the $61 million present value benefit of ADITC and EDFIT applied to reduce the amount securitized above plus $42 million of interest through the date of securitization. The $103 million will be deferred pending a final determination of whether a normalization violation would occur. See "Other Texas Restructuring Matters" section below for further details.

TCC will accrue interest expense until its net CTC refund is completed. The interest expense on the net CTC amount is $22 million for the year ended December 31, 2006 and is included in Interest Expense on TCC's 2006 Consolidated Statement of Income.

Impairment Assessment of Net True-up Regulatory Assets

TCC performed a probability of recovery impairment test on TCC's recorded net true-up regulatory asset as of September 30, 2006, after receipt of the final securitization order, and again as of December 31, 2006 after receipt of the final CTC order. At both dates, TCC determined that the projected net cash flows from the securitization less the proposed CTC refund would provide more than sufficient net positive cash flows to recover TCC's recorded net true-up regulatory asset. Accordingly, no impairment was recorded at either date.

At December 31, 2006, TCC's Consolidated Balance Sheet reflects a securitization bond liability of $2.335 billion of which $595 million is from the initial 2002 securitization, a securitization transition asset of $2.158 billion of which $542 million is from the initial 2002 securitization, and a net true-up regulatory liability for other true-up items of $155 million as a result of the True-up Proceeding.

Texas District Court Appeal Proceedings

TCC appealed the PUCT orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections below.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final true-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC's nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge's other preliminary determinations that affirm the PUCT's decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management concluded it is probable that the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. We cannot estimate the amount at this time, but the amount could exceed TCC's Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated that the PUCT's flow-through to customers of the present value of the ADITC and EDFIT benefits would result in a normalization violation. To address the matter, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. It is anticipated that if the normalization issue is resolved consistent with the PUCT's treatment, TCC will then refund $103 million plus additional carrying costs. If such refund is ultimately determined to cause a normalization violation, TCC anticipates it will be permitted to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of December 31, 2006, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. 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 nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel

The TCC deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC discussed above. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered a reduction in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins under a FERC-approved SIA. Both TCC and TNC appealed the PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margin allocations in the federal court. Intervenors also appealed the PUCT's rulings in state court.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales allocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. We await a ruling in TCC's appeal. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the regulatory liabilities.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then existing SIA allocation method. 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. Although management cannot predict the ultimate outcome of this federal litigation, management believes that its allocations were in accordance with the then existing FERC-approved SIA.

In January 2007, TCC began refunding as part of the CTC rate rider credit described above, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund relating to the favorable Federal District Court order may be subject to being refunded only upon a successful appeal by the PUCT. See "TNC's True-up Proceeding" section below for status of TNC's over-recovered fuel refund.

Excess Earnings

In 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. To date, TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. The Supreme Court of Texas requested briefing, which has been provided, but it has not decided whether it will hear the case. If the Court of Appeals decision is upheld and the refund mechanism is found to be unlawful, the impact on TCC would then depend on: (a) how and if TCC is ordered by the PUCT to refund the excess earnings to ultimate customers and (b) whether it will be able to recover the amounts previously refunded to the REPs including the REP TCC sold to Centrica. Management is unable to predict the ultimate outcome of this litigation and its effect on future results of operations and cash flows.

TNC's True-up Proceeding

TNC filed with the PUCT in August 2005 to establish a credit rider to refund its $21 million net true-up regulatory liability. In December 2005, that proceeding was suspended, pending a final ruling from TNC's appeal to the federal court regarding the fuel proceeding (described above). In August 2006, the suspension was lifted and the proceeding resumed. The PUCT approved a settlement that recommended implementing a $13 million interim refund over six-months beginning in September 2006 of the net true-up regulatory liability, exclusive of the $8 million federal court fuel issue. TNC is accruing interest expense on the unrefunded balance and will continue to do so until the balance is fully refunded. TNC anticipates a final PUCT decision regarding this proceeding in 2007. The appeals to the state and federal courts are ongoing.

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo's and approximately 3% of TNC's businesses were in SPP. We filed a petition in May 2006, requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, we received our final regulatory approval for the transfers. The transfers were effective February 2007. As required by the Arkansas Public Service Commission, SWEPCo will amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

OTHER TEXAS RATE MATTERS

ERCOT PTB Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and the 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 respective former affiliated REPs). In 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 in 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the decision to the Supreme Court of Texas, which ordered full briefing. In February 2007, the Supreme Court of Texas denied review. No motions for rehearing have been filed and management believes the matter is now final.

TCC and TNC Energy Delivery Base Rate Filings

TCC and TNC each filed a rate case for recovery of the cost of transmission and distribution energy delivery services (wires) in Texas. TCC and TNC requested $81 million and $25 million in annual increases, respectively. Both requests include a return on common equity of 11.25% and the impact of the expiration of the CSW merger savings rate credits. We expect the new base wires rates to become effective, subject to refund, in the second quarter of 2007 with a decision from the PUCT expected in the third quarter of 2007.

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 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 in April 2006 that they would not pursue the matter further.

SWEPCo Fuel Reconciliation – Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations. SWEPCo sought, in the proceedings, to include underrecoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The intervenor recommendations ranged from a $10 million to $28 million reduction. In February 2007, the PUCT staff filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced by $10 million. SWEPCo does not agree with the intervenor's or staff's recommendations and filed rebuttal testimony in February 2007. Management is unable to predict the outcome of this proceeding or its effect on future results of operations and cash flows.

Virginia Rate Matters

Virginia Restructuring

In April 2004, the Governor of Virginia signed legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo is deferring incremental environmental generation costs and incremental reliability costs for future recovery and is amortizing a portion of such deferrals commensurate with recovery. See the "APCo Virginia Environmental and Reliability Costs" section below for further details.

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

APCo Virginia Environmental and Reliability Costs

The amended 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 on and 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 1, 2004 through September 30, 2005.

In November 2006, the Virginia SCC issued a final order that rejected the staff's and the Hearing Examiner's interpretation of the law, which would have resulted in the inability to record a regulatory asset and would have ultimately prevented APCo from recovering its full incremental E&R costs incurred since July 1, 2004. The order approved an increase in APCo's rates to recover $21 million of incremental E&R costs previously incurred from

July 1, 2004 through September 30, 2005 by means of a surcharge, effective December 1, 2006 through November 30, 2007. As a result, in the fourth quarter of 2006, APCo commenced recovery of the approved E&R rate rider and deferred as a regulatory asset, $60 million of incremental E&R costs incurred from July 1, 2004 through September 30, 2006 based on the Virginia SCC's order and reversed $11 million of related AFUDC and capitalized interest, thereby increasing pre-tax earnings by $49 million. In addition, APCo has identified but not recognized $10 million of equity carrying costs on incremental E&R capital expenditures, which are not recognizable until collected. The order requires APCo to keep track, for true-up purposes, of base rate and surcharge recoveries of incremental E&R costs on a continuing basis to avoid any double recovery. During 2007 we will file for recovery of incremental E&R costs incurred from October 1, 2005 through September 30, 2006. The Virginia base rate case increase implemented October 2, 2006, subject to refund, is currently recovering an ongoing level of incremental E&R costs incurred since September 30, 2006 and as a result, we ceased deferring such costs incurred after that date.

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 the cost of its investment in environmental equipment and a return on equity of 11.5%. 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 trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which is estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase being collected, subject to refund, includes recovery of incremental E&R costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovery sought through the E&R surcharge mechanism previously discussed if not recovered through base rates. In October 2006, the Virginia SCC staff filed their direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. Management reserved a portion of the revenue subject to refund that in its opinion is not probable of recovery. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006. APCo expects a ruling during 2007. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

West Virginia Rate Matters

APCo and WPCo West Virginia Rate Case

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

- A $56 million increase in Expanded Net Energy Cost (ENEC) for fuel, purchased power expenses, off-system sales credits and other energy-related costs (the ENEC is an expanded form of a fuel clause mechanism which includes all energy-related costs);
- A $23 million special construction surcharge providing recovery of the costs of scrubbers and the new Wyoming-Jacksons Ferry 765 kV line to date;
- An $18 million general base rate reduction resulting predominantly from a reduction in the return on equity to 10.5% and a $9 million reduction in depreciation expense which affects cash flows but not earnings; and
- A $17 million credit to refund a portion of deferred prior over-recoveries of ENEC of $51 million, recorded in regulatory liabilities on the Consolidated Balance Sheets, which will impact cash flows but not earnings.

In addition, the agreement provided a mechanism that allows APCo and WPCo to adjust their special construction surcharges annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at APCo's Mountaineer and John Amos power plants and the costs of the new Wyoming-Jacksons Ferry 765 kV line. APCo and WPCo plan to file in March 2007 with the WVPSC for the first adjustment to their special construction surcharge, providing an incremental annual increase of $29 million to be effective July 1, 2007. APCo estimates annual increases in revenues of $14 million effective July 1, 2008 and $18 million effective July 1, 2009, subject to review by the WVPSC.

Under the settlement, the ENEC mechanism was reinstated effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel, purchased power costs, off-system sales margins and other energy-related costs beginning in 2007. The settlement provides for the return to customers of the remaining $34 million of the prior ENEC regulatory liability plus interest at a LIBOR rate (London Interbank Offered Rate) on the unrefunded balance in future ENEC proceedings.

APCo IGCC

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, WV. In January 2007, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 3, 2007. The order also cancels a previously-approved procedural schedule. Through December 31, 2006, APCo deferred pre-construction IGCC costs totaling $10 million.

Indiana Rate Matters

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. An order issued by the IURC in October 2006 did not dispute our revised depreciation accounting rates but, nevertheless, denied I&M's request to revise its book depreciation rates between base rate cases. In November 2006, I&M filed with the IURC a petition for reconsideration of the October order as well as a notice of appeal to the Indiana Court of Appeals. In January 2007, the IURC denied I&M's petition for reconsideration.

In February 2007, I&M withdrew its appeal of the IURC order and filed a new request with the IURC for approval of the revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counselor that would provide direct benefits to I&M's customers if new depreciation rates are approved by the IURC. The direct benefits would include a $5 million credit in fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement is approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the 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 Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed the book depreciation reduction would increase earnings but would not impact cash flows until rates are revised. I&M requested expeditious review and approval of its filing, but management cannot predict the outcome of the request.

Kentucky Rate Matters

KPCo Rate Filing

In March 2006, the KPSC approved a settlement agreement in KPCo's 2005 base rate case. The approved agreement provided 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 was 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 AFUDC.

KPCo Environmental Surcharge Filing

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo requested recovery of approximately $2 million of additional revenue in 2007 and an additional $6 million in 2008 for a total of $8 million of additional revenue. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge.

In November 2006, the Kentucky attorney general and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005 Environmental Surcharge order. In its order, the KPSC approved KPCo's recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs it incurs as a result of the AEP Power Pool capacity settlement. The KPSC allowed KPCo to recover these FERC-approved allocated costs, via the environmental surcharge, since the KPSC's first order in the environmental surcharge case in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates.

Oklahoma Rate Matters

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 eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 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 and with $9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had 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. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC 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 sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its position. We believe that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should 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 could 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.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and we expect a recommendation from the ALJ in 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. In compliance with an OCC order, PSO is required to file its testimony by June 15, 2007. This proceeding will cover the year 2005.

Management cannot predict the outcome of the pending fuel and purchase power reviews or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

PSO Rate Filing

In November 2006, PSO filed a request to increase base rates $50 million for Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007. PSO sought a return on equity of 11.75%. PSO also proposed a formula rate plan that, if approved as filed, will permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve-months beginning six months after the test year. The formula would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and avoid recording a large amount of AFUDC that would have been recorded during the construction time period. Hearings are scheduled to begin in May, 2007.

Louisiana Rate Matters

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 Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%.

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, based on a proposed 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo will file testimony in the first quarter of 2007. Hearings are expected to occur in early 2007. A decision is not expected until mid or late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations and cash flows.

Michigan Rate Matters

Michigan Restructuring

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective on that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. As of December 31, 2006, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2006, the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

FERC Rate Matters

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. As of December 31, 2006 and 2005, the AEP East companies deferred $29 million and $31 million, respectively, of unamortized RTO and PJM 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 and related carrying costs not billed by PJM in monthly charges from November 1, 2005 through May 31, 2020. The rate, the result of a settlement, will be adjusted each year to collect $2 million on an annualized basis for 175 months. 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 approximately 85% of the transmission load in the AEP zone. As a result, the AEP East companies will need to recover the 85% through their retail rates.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of the deferred PJM-billed integration costs, including related carrying charges, of AEP, Commonwealth Edison Company (ComEd) and the Dayton Power and Light Company from all present zones of the PJM region, except the Virginia Electric & Power Company (VEPCo) zone. The net result of the settlement is that the AEP East companies will recover approximately 50% of the deferred PJM-billed integration costs from third parties, and will need to recover the remaining 50% through retail rates.

As a result of recently approved rate increases, CSPCo, OPCo, KPCo and APCo recover the amortization of RTO formation/integration costs billed to the AEP East companies in Ohio, Kentucky, Virginia (subject to refund) and West Virginia. In Indiana, I&M is subject to a rate cap until June 30, 2007 and is precluded from recovering its share of the deferred RTO costs until that date or until it can file for a rate increase in Indiana. I&M has not yet filed for recovery in Michigan.

If the Virginia, Indiana or Michigan commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it could result in a write-off of up to 25% of the total remaining deferred balance, adversely impacting future results of operations and cash flows. In the event of a disallowance, we would appeal that decision to the appropriate state or federal courts.

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

We eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, we would also receive refunds related to the SECA rates we paid to third parties. The AEP East companies recognized gross SECA revenues as follows:

	Gross SECA Revenues Recognized (in millions)
Year Ended December 31, 2006 (a)	$ 43
Year Ended December 31, 2005	163
Year Ended December 31, 2004	14

(a) Represents revenues through March 31, 2006, when SECA rates expired, and excludes all provisions for refund**.**

Approximately $19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these SECA billings.

In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. It would also provide insignificant refunds of SECA rates paid by the AEP East companies. Based on the completed settlements and before the issuance of the ALJ's initial decision, the AEP East companies initially provided a reserve for $22 million in net refunds.

We, together with Exelon and DP&L, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. We believe that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, we believe the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. As a consequence we recorded an additional $15 million reserve in December 2006. Although we believe we have meritorious arguments, management cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate 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 and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of 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.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in additional revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV, which would produce lower revenues for AEP than the AEP/AP proposal.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would produce considerably lower revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design that would include all transmission facilities, which would produce higher transmission revenues for AEP than the AEP/AP proposal.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favor continuation of the existing PJM rate design. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC and the Postage Stamp rate proposed by the FERC staff to be just and reasonable alternatives and recommended that the FERC staff's Postage Stamp rate proposal be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. The phase-in of Postage Stamp rates would delay the full impact of that result until about 2012.

We filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. We argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest. A FERC decision is likely before mid-2007.

To recover these lost T&O and SECA rates, we sought to increase our retail rates in most of our states. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction in new rates effective March 30, 2006.
- In Ohio, CSPCo and OPCo recover their FERC-approved OATT that reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.
- In Michigan, I&M has not filed to seek recovery of the lost transmission revenues.

We presently recover from retail customers approximately 85% of the reduction in transmission revenues of $128 million a year.

Once approved by the FERC, the favorable impacts of the new regional PJM rate design will flow directly to wholesale customers and to retail customers in West Virginia through the ENEC and to retail customers in Ohio upon PUCO approval of a filing we would make to reflect the new rates in the Transmission Cost Recovery Rider. In Kentucky, Indiana, Virginia and Michigan, the additional transmission revenues can be expected to reduce retail rates in future base rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. We believe that the AEP/AP proposal or the Postage Stamp proposal combined with the retail rate recovery discussed above would be an effective replacement for the eliminated T&O and SECA rates. 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. The resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates on a timely basis especially in Indiana, where there is a rate freeze until June 30, 2007, and Michigan.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement which allowed increases in our wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006 when the new Wyoming-Jacksons Ferry 765 kV line went into service. Wholesale transmission revenues increased approximately $23 million in 2006 due to this rate increase. We estimate that this rate increase will increase wholesale transmission revenues by $35 million in 2007.

Calpine Oneta Power, L.P.'s Request at the FERC for Reactive Power Compensation From SPP

In April 2003, Calpine Oneta Power (Calpine), an IPP, filed at the FERC a proposed rate schedule to charge SPP for reactive power from Calpine's generating facility. The FERC rate schedule included a fixed annual fee of $2 million. PSO, SWEPCo and, until February 2007, a small portion of TNC operated in SPP. In September 2006, the FERC issued an order reversing an ALJ initial decision, granting Calpine's request and requiring Calpine to make a compliance filing within 30 days. Our share of this SPP expense could be approximately 90% of the total amount billed by Calpine. Based on this information, in 2006 we recorded a provision, including interest, of $9 million for the retroactive reactive power liability. We requested rehearing at the FERC.

Calpine issued invoices to AEP for service and interest charges from June 2003 through December 2006 totaling $10 million. We objected to these invoices, in part, on the basis that Calpine seeks to collect its entire revenue requirement from us, leaving us with the risk of collecting the portion that may be owed by other service providers in the AEP zone of SPP. Meanwhile, in December 2006, SPP filed a new rate schedule. If the new rate schedule is approved, it will be generally applicable throughout SPP for reactive power service. If the FERC accepts the new rate, on a going forward basis from March 2007, we will owe an immaterial amount to Calpine for its reactive power production capability. The new tariff compensates generators for the reactive service they actually provide rather than the capability they possess.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement

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 effective April 1, 2006 and beyond. The approved allocation methodology for the AEP East companies and AEP West companies 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, which effectively allowed the AEP West companies to share in PJM and MISO regional margins in the East. In February 2006, we filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because they are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA effective April 1, 2006 and CSW Operating Agreement effective May 1, 2006.

Our total trading and marketing margins are unaffected by the allocation methodology. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of expanded net energy fuel clause recovery mechanisms and related off-system sales sharing mechanisms by state. However, the new allocation method is expected to increase the net system sales margins allocated to the AEP East companies, who flow considerably less of these margins through expanded fuel clause mechanisms and more in base rates than do the AEP West companies. As a result, the change in allocation methods should tend to increase future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2006	December 31, 2005	Notes
	(in millions)		
Regulatory Assets:			
Current Regulatory Asset –			
Under-recovered Fuel Costs	$ 38	$ 197	(c) (j)
SFAS 158 Regulatory Asset (Notes 2 and 9)	$ 875	$ -	(a)
SFAS 109 Regulatory Asset, Net (Note 13)	771	785	(c) (i)
Transition Regulatory Assets – Ohio and Virginia (Note 4)	185	306	(a) (k)
Designated for Securitization – Texas	-	1,436	(d)
Unamortized Loss on Reacquired Debt	105	110	(b) (l)
Unrealized Loss on Forward Commitments	89	92	(a) (i)
Texas Wholesale Capacity Auction True-up (Note 4)	-	77	(e)
Refunded Excess Earnings (Note 4)	56	55	(n)
Cook Nuclear Plant Refueling Outage Levelization	47	23	(a) (f)
Other	349	378	(c) (i)
Total Noncurrent Regulatory Assets	$ 2,477	$ 3,262	
Regulatory Liabilities:			
Current Regulatory Liability –			
Over-recovered Fuel Costs (o)	$ 37	$ 3	(c) (j)
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,610	$ 1,437	(g)
Deferred Investment Tax Credits	332	361	(c) (m)
Excess ARO for Nuclear Decommissioning Liability (Note 10)	323	271	(h)
Unrealized Gain on Forward Commitments	181	168	(a) (i)
TCC CTC Refund	155	238	(e)
Other	309	272	(c) (i)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,910	$ 2,747	

(a) Does not earn a return.
(b) Amount effectively earns a return.
(c) Includes items both earning and not earning a return.
(d) Amount includes a carrying cost and was included in TCC's True-up Proceeding and securitized in October 2006. The cost of the securitization bonds will be recovered over a 14 year period. Amount is included within Securitized Transition Assets on the Consolidated Balance Sheet for 2006. See "TCC Texas Restructuring" section of Note 4.
(e) Net amounts were ordered to be refunded through the CTC. TCC's net refund began on an interim basis in October 2006. In a final order issued December 2006, the PUCT set the final net refund to be completed by June 2008. CTC refunds for TCC accrue interest until the refunds are completed. See "TCC's 2006 CTC Proceeding" section of Note 4.
(f) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
(g) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(h) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, accrues monthly, and will be paid when the nuclear plant is decommissioned.
(i) Recovery/refund period - various periods.
(j) Recovery/refund period - 1 year.
(k) Recovery/refund period - up to 4 years.
(l) Recovery/refund period - up to 37 years.
(m) Recovery/refund period - up to 56 years.
(n) Recovery method and timing to be determined in future proceeding.
(o) Current Regulatory Liability – Over-recovered Fuel Costs are recorded in Other on our Consolidated Balance Sheets.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reduction of $221 million over 6 years. In 2006, TCC and TNC requested to have these rate reductions eliminated. See "TCC and TNC Energy Delivery Base Rate Filings" section of Note 4.
Indiana – I&M	Rate reduction of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements.

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers and various Lloyds of London syndicates.

See Note 10 for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our results of operations, cash flows and financial condition.

COMMITMENTS

The AEP System has substantial construction commitments to support its operations and environmental investments. Aggregate construction expenditures for 2007 for consolidated operations are estimated at approximately $3.5 billion plus $427 million of announced purchases of gas-fired generating units. 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, weather, legal reviews and the ability to access capital.

Our subsidiaries enter into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2029. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

Our subsidiaries purchase materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. We do not expect to incur penalty payments under these provisions that would materially affect our results of operations, cash flows or financial condition.

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 December 31, 2006, the maximum future payments for all the LOCs are approximately $26 million with maturities ranging from March 2007 to November 2007.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides 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 Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of December 31, 2006, SWEPCo has collected approximately $29 million through a rider for final mine closure costs, of which approximately $12 million is recorded in Deferred Credits and Other and approximately $17 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

SWEPCo is the only customer of Sabine and Sabine charges SWEPCo all its costs which are included in the cost of fuel and passed through SWEPCo's fuel clause.

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. 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 $2.2 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of this note). 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 are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2006, the maximum potential loss for these lease agreements was approximately $56 million ($36 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 14 for disclosure of other lease residual value guarantees.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states allege 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 alleged modifications occurred at our generating units over a twenty-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

Under the CAA, if a plant undertakes a major modification that 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 routine maintenance, replacement of degraded equipment or failed component 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.

Cases are 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 were 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 were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted 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. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. The Federal EPA also 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, if any, 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 our future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the second quarter of 2007.

In 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.

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

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and 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. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. We believe the actions are without merit and intend to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2006, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites. There are nine additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at two sites under state law. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

We evaluated the potential liability for each Superfund site separately, but several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, our results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

Plaquemine Cogeneration Facility

Juniper Capital L.P. (Juniper) constructed and financed our ownership interest in the Plaquemine Cogeneration Facility (the 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.

In August 2006, we reached an agreement with Dow to sell the Facility to them and recorded a pretax impairment of $209 million (see "Dispositions" section of Note 8). The sale closed in November 2006. Upon closing, we repaid our recorded $525 million lease financing obligation, which was included in Long-term Debt on our Consolidated Balance Sheets at December 31, 2005.

Prior to the sale, Dow used a portion of the energy produced by the Facility and sold the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a twenty-year term. OPCo sold the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market until the sale of the Facility. With the sale of the Facility, OPCo terminated its purchase agreement with Dow.

TEM Litigation

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). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

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 August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus prejudgment interest. Any eventual proceeds will be recorded as a gain when received.

In September 2005, TEM posted a $142 million letter of credit as security pending appeal of the judgment. Both parties filed Notices of Appeal with the United States Court of Appeals for the Second Circuit, which heard oral argument on the appeals in December 2006. We cannot predict the ultimate outcome of this proceeding.

Enron Bankruptcy

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

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which 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 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 facility. In 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court's judgment and dismissed the BOA Syndicate's case. The BOA Syndicate did not seek review of this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL's motion to have the case assigned to the judge who heard the case originally was granted. HPL intends to defend against any renewed claims by BOA.

In 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 facility 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 facility 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. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. The case in federal court in Texas is set for trial beginning April 2007.

In February 2007, the Judge in the New York action, after hearing oral argument on the motions for summary judgment, made a series of oral "informal findings" and submitted a written memorandum to the parties' counsel. In the memorandum to counsel, the Judge stated that he was denying several of AEP's motions for partial summary judgment, granting several of BOA motions for summary judgment and denying others. The substantive matters left open for further proceedings include the issue of the nature of the gas subject to BOA security interest and the value of that interest. The Judge stated that the memorandum to counsel is not an opinion or an order, and that no opinion or order will be issued until all motions pending before the Court have been decided. At this time we are unable to predict how the Judge will rule on the pending motions due to the complexity of those issues and the parties' disagreement over each issue. If the Judge issues a judgment directing AEP to pay an amount in excess of the gain on the sale of HPL described below and if AEP is unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on the results of operations and cash flow.

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 are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. In 2003, Enron filed a complaint in the Bankruptcy Court against

AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim sought to unwind the effects of the transaction. In 2005, the parties reached a settlement resulting in a pretax cost of approximately $46 million.

Enron Bankruptcy – Summary – The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities were counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities, the settlement agreement and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, there is a dispute regarding the cushion gas agreement. 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 or financial condition.

Shareholder Lawsuits

In 2002 and 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 were pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, the plaintiffs filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal was completed in December 2006 and the parties await the scheduling of oral argument. We intend to continue to defend against these claims.

Natural Gas Markets Lawsuits

In 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 were 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 were transferred to the United States District Court for the District of Nevada but subsequently were remanded to California state court. In 2005, the judge in Nevada dismissed three of the remaining cases (AEP was a defendant in one of these cases), on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. We will continue to defend each case where an AEP company is a defendant.

Cornerstone Lawsuit

In 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 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 December 2006, we agreed to settle all claims with the plaintiffs without material impact on our results of operations or financial condition.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. In 2003, the CFTC filed a complaint against AEP and AEPES in federal District Court. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities. Our settlements did not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made settlement payments to the agencies in 2005 in accordance with the respective contractual terms. The agencies' investigations and the CFTC litigation ended. During 2004, we provided for the settlements payment in the amount of $36 million (nondeductible for federal income tax purposes). There was no impact on 2006 or 2005 results of operations as a result of the settlements.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). 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 Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered as the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a 2005 company-wide staffing and budget review, we identified approximately 500 positions for elimination. We recorded pretax severance benefits expense of $28 million, which is primarily reflected in Other Operation and Maintenance on our 2005 Consolidated Statement of Income. Approximately 95% of the expense was within the Utility Operations segment. The following table shows the total 2005 expense recorded and the activity during 2005 and 2006, which eliminated the accrual as of June 30, 2006:

	Amount (in millions)
Total Expense	$ 28
Less: Total Payments	16
Accrual at December 31, 2005	12
Less: Total Payments	8
Less: Accrual Adjustments	4
Accrual at December 31, 2006	$ -

The December 31, 2005 accrual was primarily reflected in Current Liabilities – Other on our Consolidated Balance Sheets. The favorable accrual adjustments were recorded primarily in Other Operation and Maintenance on our Consolidated Statements of Income.

8. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS AND ASSETS HELD FOR SALE

ACQUISITIONS

Acquisitions Anticipated Being Completed During the First Half of 2007

Darby Electric Generating Station (Utility Operations segment)

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station (Utility Operations segment)

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the second quarter of 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW.

<u>2006</u>

None

<u>2005</u>

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC, a subsidiary of PSEG, for the purchase of the Waterford Plant in Waterford, Ohio. The Waterford Plant is a natural gas, combined cycle power plant with a generating capacity of 821 MW. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power Company (Monongahela Power), which includes approximately 29,000 customers. In August 2005, we agreed to terms of a transaction, which included the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of CSPCo's customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of the Ceredo Generating Station located near Ceredo, West Virginia. The Ceredo Generating Station is a natural gas, simple cycle power plant with a generating capacity of 505 MW. This transaction was completed in December 2005 for $100 million.

<u>2004</u>

None

DISPOSITIONS

<u>2006</u>

Compresion Bajio S de R.L. de C.V. (All Other)

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, which resulted in a pretax other-than-temporary impairment charge of approximately $7 million. The impairment amount is classified in Investment Value Losses on our 2005 Consolidated Statement of Income. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

Plaquemine Cogeneration Facility (All Other)

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We recorded a pretax impairment of $209 million ($136 million, net of tax) in the third quarter of 2006 based on the terms of the agreement to sell the Facility to Dow. We recorded the impairment in Asset Impairments and Other Related Charges on our 2006 Consolidated Statement of Income. The Facility does not meet the criteria for discontinued operations reporting.

We completed the sale in the fourth quarter of 2006. Excluding the 2006 impairment of $209 million discussed above, the effect of the sale on our 2006 results of operations was not significant. In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. As a result of the sale, Dow reduced an existing below-current-market long-term power supply contract with us in Texas by 50 MW and we retained the right to any judgment paid by TEM for breaching the original Power Purchase and Sale Agreement. See "TEM Litigation" section of Note 6.

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

See the following 2005 disclosure "Intercontinental Exchange, Inc. (ICE) Initial Public Offering" for information regarding sales in 2006.

2005

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

In November 2000, we made our initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. We sold approximately 2.1 million shares (71% of our investment in ICE) in the fourth quarter of 2005 and recognized a $47 million pretax gain ($30 million, net of tax). During 2006, we sold approximately 0.6 million shares and recognized a $39 million pretax gain ($25 million, net of tax). We recorded the gains in Interest and Investment Income on our Consolidated Statements of Income. Our remaining investment of 0.3 million shares is recorded in Other Temporary Cash Investments on our Consolidated Balance Sheets.

Houston Pipe Line Company LP (HPL) (All Other)

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 $380 million and $379 million as of December 31, 2006 and 2005, respectively, which are reflected in Deferred Credits and Other on our Consolidated Balance Sheets. We provided an indemnity to the purchaser in an amount up to the purchase price 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 6). 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 hold forward gas contracts, with expirations through 2010, not sold with the gas pipeline and storage assets. We manage the commodity price risk associated with these forward gas contracts to limit our price risk exposure principally by entering into equal and offsetting contracts. For the year ended December 31, 2006, the change in the mark-to-market value of these contracts was less than $100,000.

Pacific Hydro Limited (All Other)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated in July 2005 and we recognized a pretax gain of $56 million. This gain is classified in Gain on Disposition of Equity Investments, Net on our 2005 Consolidated Statement of Income.

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 Centrica and us 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 we 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 operating results and is contractually capped at $20 million. The payments are reflected in (Gain) Loss on Disposition of Assets, Net on our Consolidated Statements of Income.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System which included all of the generation facilities owned by our Registrant Subsidiaries.

2004

Pushan Power Plant (All Other)

In 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. The sale was completed in March 2004 for $61 million. The effect of the sale on our 2004 results of operations was not significant. Results of operations of Pushan are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

LIG Pipeline Company and its Subsidiaries (All Other)

As a result of our 2003 decision to exit our noncore businesses, we actively marketed LIG Pipeline Company, which had approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana, and five gas processing facilities that straddle the system. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's gas storage assets. (See "Jefferson Island Storage & Hub, LLC" section of this note for further information.) In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76 million was completed in April 2004 and the impact on results of operations in 2004 was not significant. The results of operations are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

Jefferson Island Storage & Hub, LLC (All Other)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, LLC (JISH). The sale of JISH and its assets for $90 million was completed in October 2004. The sale resulted in a pretax loss of $12 million ($2 million, net of tax). The results of operations and loss on sale of JISH are classified in Discontinued Operations on our 2004 Consolidated Statement of Income. See "Discontinued Operations" section of this note for additional information.

AEP Coal, Inc. (All Other)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal, Inc." During 2002, the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production was expected to continue below historical levels.

In 2003, as a result of management's decision to exit our noncore businesses, we retained an advisor to facilitate the sale of AEP Coal, Inc. In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal, Inc. We received approximately $9 million cash and the buyer assumed an additional $11 million in future reclamation liabilities. We retained an estimated $37 million in future reclamation liabilities which has since been reduced to approximately $14 million. The sale closed in April 2004 and the effect of the sale on our 2004 results of operations was not significant.

Independent Power Producers (Generation and Marketing segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). In March 2004, we entered into an agreement to sell the four domestic IPP investments for a total sales price of $156 million, subject to closing adjustments. A pretax impairment of $2 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of all four investments in 2004. The sale resulted in a pretax gain of $105 million ($64 million, net of tax) generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded in Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Income.

U.K. Generation (All Other)

In December 2001, we acquired two coal-fired generation plants in the U.K. for a cash payment of $942 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future.

In the fourth quarter of 2003, the U.K. generation plants were determined to be noncore assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddler's Ferry and Ferrybridge), related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pretax gain of $266 million ($128 million, net of tax). As a result of the sale, the buyer assumed an additional $46 million in future reclamation liabilities and $10 million in pension liabilities. The remaining assets and liabilities include certain physical power and capacity positions and financial coal and freight swaps. Substantially all of these positions matured or were settled with the applicable counterparties during 2005. The results of operations and gain on sale are included in Discontinued Operations, Net of Tax on our Consolidated Statements of Income for the year ended December 31, 2004. See "Discontinued Operations" section of this note for additional information.

Texas Plants – TCC Generation Assets (Utility Operations segment)

In relation to the implementation of the Texas Restructuring Legislation, we signed an agreement in March 2004 to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on our 2004 results of operations.

South Coast Power Limited (All Other)

South Coast Power Limited (SCPL) is a 50% owned venture that was formed in 1996 to build, own and operate Shoreham Power Station, a 400 MW, combined-cycle, gas turbine power station located in Shoreham, England. In 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $47 million, resulting in a pretax gain of $48 million ($31 million, net of tax). This gain was recorded in Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Income.

Excess Real Estate (Utility Operations segment)

In June 2004, we entered into negotiations to sell an under-utilized building in Dallas, Texas obtained through our merger with CSW in 2000. A pretax impairment of $3 million was recorded in Other Operation and Maintenance on our Consolidated Statements of Income during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building for $8 million. The sale did not have a significant effect on our results of operations.

Numanco LLC (All Other)

In November 2004, we completed the sale of Numanco LLC for a sale price of $25 million. Numanco was a provider of staffing services to the utility industry. The sale did not have a significant effect on our 2004 results of operations.

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and are classified as such in 2006, 2005 and 2004. Results of operations of these businesses are classified as shown in the following table:

	SEE-BOARD (a)	Pushan Power Plant	LIG (b)	U.K. Generation (c)	Total
			(in millions)		
2006 Revenue	$ -	$ -	$ -	$ -	$ -
2006 Pretax Income	-	-	-	9	9
2006 Earnings, Net of Tax	5	-	-	5	10
2005 Revenue (Expense)	$ 13	$ -	$ -	$ (7)	$ 6
2005 Pretax Income (Loss)	10	-	-	(13)	(3)
2005 Earnings (Loss), Net of Tax	24	-	5	(2)	27
2004 Revenue	$ -	$ 10	$ 165	$ 125	$ 300
2004 Pretax Income (Loss)	(3)	9	(12)	164	158
2004 Earnings (Loss), Net of Tax	(2)	6	(12)	91	83

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.
(c) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

2006

We recorded a pretax impairment of assets totaling $209 million as a result of the terms of our agreement to sell the Plaquemine Cogeneration Facility to Dow. See "Plaquemine Cogeneration Facility" section of this note for additional information regarding this sale.

2005

We recorded pretax impairments of assets totaling $46 million ($39 million related to asset impairments and $7 million related to an equity investment impairment) that reflected our decision to retire two generation units and our decision to exit noncore businesses and other factors as follows:

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following management's extensive review of the commercial viability of our generation fleet, management committed to a plan to retire CSPCo's Conesville Units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville Units 1 and 2 were considered retired as of the third quarter of 2005.

We recognized a pretax charge of approximately $39 million in 2005 related to our decision to retire the units. The impairment amount is classified in Asset Impairments and Other Related Charges on our 2005 Consolidated Statement of Income.

Compresion Bajio S de R.L. de C.V. (All Other)

In January 2002, we acquired Bajio. A pretax other-than-temporary impairment charge of $13 million was recognized in December 2004 based on an indicative bid, which did not result in a sale.

In September 2005, a pretax other-than-temporary impairment charge of approximately $7 million was recognized based on an indicative offer received in September 2005. Both the 2005 and 2004 impairment amounts are classified as Investment Value Losses on our Consolidated Statements of Income. The sale was completed in February 2006 without significant effect on our 2006 results of operations.

2004

We recorded pretax impairments of assets (including goodwill) and investments totaling $18 million ($15 million related to equity investments recorded in Investment Value Losses and $3 million related to charges recorded for excess real estate in Other Operation and Maintenance on our Consolidated Statement of Income) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

The categories of impairments and gains on dispositions include:

	Year Ended December 31, 2006	2005	2004
Asset Impairments and Other Related Charges (Pretax)		(in millions)	
Plaquemine Cogeneration Facility	$ 209	$ -	$ -
Conesville Units 1 and 2	-	39	-
Total	$ 209	$ 39	$ -
(Gain) Loss on Disposition of Assets, Net (Pretax)			
Texas REPs	$ (70)	$ (112)	$ -
Miscellaneous Property, Plant and Equipment	1	(8)	(4)
Total	$ (69)	$ (120)	$ (4)
Investment Value Losses (Pretax)			
Independent Power Producers	$ -	$ -	$ (2)
Bajio	-	(7)	(13)
Total	$ -	$ (7)	$ (15)
Gain on Disposition of Equity Investments, Net (Pretax)			
Independent Power Producers	$ -	$ -	$ 105
South Coast Power Limited	-	-	48
Pacific Hydro Limited	-	56	-
Other	3	-	-
Total	$ 3	$ 56	$ 153

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 Brownsville (the nonaffiliated co-owners). By May 2004, we received notice from the nonaffiliated co-owners 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. Golden Spread challenged these agreements in State District Court in Dallas County. Golden Spread alleges that the Public Utilities Board of the City of Brownsville 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 in October 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas.

In May 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, which was denied. Golden Spread then appealed to the Supreme Court of Texas and on December 15, 2006, its Petition for review was denied. Various contract claims, between the parties, that were severed from the appeal on the right of first refusal are pending in the District Court of Dallas County.

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. The sale did not have a significant effect on our results of operations nor do we expect the remaining litigation to have a significant effect on our results of operations.

TCC's assets related to the Oklaunion Power Station are classified in Assets Held for Sale on our Consolidated Balance Sheets at December 31, 2006 and 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.

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

	December 31,	
Texas Plants	**2006**	**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

We sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. We sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees. We implemented FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" in 2004. The Medicare subsidy reduced our SFAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

In December 2006, we implemented SFAS 158. The effect of this standard on our financial statements was a pretax AOCI adjustment of $1,236 million that was offset by a SFAS 71 regulatory asset of $875 million and a deferred income tax asset of $126 million resulting in a net of tax AOCI equity reduction of $235 million. See Note 2.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2006, and their funded status as of December 31 of each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2006 and 2005

	Pension Plans		Other Postretirement Benefit Plans	
	2006	2005	2006	2005
Change in Projected Benefit Obligation	(in millions)			
Projected Obligation at January 1	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Service Cost	97	93	39	42
Interest Cost	231	228	102	107
Participant Contributions	-	-	21	20
Actuarial (Gain) Loss	(293)	191	(55)	(320)
Plan Amendments	2	-	-	-
Benefit Payments	(276)	(273)	(112)	(118)
Medicare Subsidy Accrued	-	-	(8)	-
Projected Obligation at December 31	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Actual Return on Plan Assets	470	224	127	70
Company Contributions	9	637	94	107
Participant Contributions	-	-	21	20
Benefit Payments	(276)	(273)	(112)	(118)
Fair Value of Plan Assets at December 31	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Funded Status				
Funded Status at December 31	$ 238	$ (204)	$ (516)	$ (659)
Unrecognized Net Transition Obligation	-	-	-	152
Unrecognized Prior Service Cost (Benefit)	-	(9)	-	5
Unrecognized Net Actuarial Loss	-	1,266	-	471
Net Asset (Liability) Recognized	$ 238	$ 1,053	$ (516)	$ (31)

Amounts Recognized on the Balance Sheets as of December 31, 2006 and 2005

	Pension Plans		Other Postretirement Benefit Plans	
	2006	2005	2006	2005
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 320	$ 1,099	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	-	(5)	-
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(74)	(46)	(511)	(31)
Funded Status	238		(516)	
Regulatory Assets	582	N/A	293	N/A
Deferred Income Taxes	60	10	66	N/A
Additional Minimum Liability	N/A	(35)	N/A	N/A
Intangible Asset	N/A	6	N/A	N/A
Accumulated Other Comprehensive Income (Loss), Net of Tax	112	19	123	N/A
Total	$ 992	$ 1,053	$ (34)	$ (31)

N/A = Not Applicable

SFAS 158 Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2006

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 759	$ 354
Prior Service Cost (Credit)	(5)	4
Transition Obligation	-	124
Pretax AOCI	$ 754	$ 482
Recorded as		
Regulatory Assets	$ 582	$ 293
Deferred Income Taxes	60	66
Net of tax AOCI	112	123
Pretax AOCI	$ 754	$ 482

We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery.

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2006 and 2005, and the target allocation for 2007, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2007	2006	2005
Asset Category		(in percentage)	
Equity Securities	65	63	62
Real Estate	5	6	4
Debt Securities	28	26	25
Cash and Cash Equivalents	2	5	9
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2006 and 2005, and target allocation for 2007, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2007	2006	2005
Asset Category		(in percentage)	
Equity Securities	65	66	68
Debt Securities	33	32	30
Other	2	2	2
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified portfolio of investments to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. To minimize risk, our employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Our investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. Our investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies. Because of the $320 million contribution at the end of 2005 the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006.

The value of our pension plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005. The qualified plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.3 billion in December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation

	2006	2005
	(in millions)	
Qualified Pension Plans	$ 3,861	$ 4,053
Nonqualified Pension Plans	78	81
Total	$ 3,939	$ 4,134

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2006 and 2005 were as follows:

	Underfunded Pension Plans As of December 31,	
	2006	2005
	(in millions)	
Projected Benefit Obligation	$ 82	$ 84
Accumulated Benefit Obligation	$ 78	$ 81
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 78	$ 81

We made a contribution of $626 million in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2006	2005	2006	2005
	(in percentages)			
Discount Rate	5.75	5.50	5.85	5.65
Rate of Compensation Increase	5.90(a)	5.90(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, we use a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2006, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.90%.

Estimated Future Benefit Payments and Contributions

Information about the 2007 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contribution	**Pension Plans**	**Other Postretirement Benefit Plans**
	(in millions)	
Required Contributions (a)	$ 8	N/A
Additional Discretionary Contributions	-	$ 82

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.

N/A = Not Applicable

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to fund nonqualified benefit payments, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans' trust is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes and is provided for in agreements with state regulatory authorities.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	Pension Plans	**Other Postretirement Benefit Plans**	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2007	$ 345	$ 113	$ (9)
2008	354	121	(10)
2009	361	130	(11)
2010	366	139	(11)
2011	367	149	(12)
Years 2012 to 2016, in Total	1,821	839	(77)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for fiscal years 2006, 2005 and 2004:

	Pension Plans			Other Postretirement Benefit Plans		
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service Cost	$ 97	$ 93	$ 86	$ 39	$ 42	$ 41
Interest Cost	231	228	228	102	107	117
Expected Return on Plan Assets	(335)	(314)	(292)	(94)	(92)	(81)
Amortization of Transition Obligation	-	-	2	27	27	28
Amortization of Prior Service Cost (Credit)	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	79	55	17	22	25	36
Net Periodic Benefit Cost	71	61	40	96	109	141
Capitalized Portion	(21)	(17)	(10)	(27)	(33)	(46)
Net Periodic Benefit Cost Recognized as Expense	$ 50	$ 44	$ 30	$ 69	$ 76	$ 95

Estimated amounts expected to be amortized to net periodic benefit costs from pretax accumulated other comprehensive income during 2007 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 52	$ 15
Prior Service Cost (Credit)	(1)	-
Transition Obligation	-	27
Total Estimated 2007 Pretax AOCI Amortization	$ 51	$ 42

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2006	2005	2004	2006	2005	2004
	(in percentages)					
Discount Rate	5.50	5.50	6.25	5.65	5.80	6.25
Expected Return on Plan Assets	8.50	8.75	8.75	8.00	8.37	8.35
Rate of Compensation Increase	5.90	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2006 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	2006	2005
Initial	8.0 %	9.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	193	(161)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans for substantially all employees who are not members of the United Mine Workers of America (UMWA). These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. Our matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled $62 million in 2006, $57 million in 2005 and $55 million in 2004.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2006, 2005 and 2004.

10. NUCLEAR

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. A significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant results from its ownership. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range is caused by variables in assumptions. I&M recovers estimated Cook Plant decommissioning costs in its rates. The amount recovered in rates for decommissioning the Cook Plant was $30 million in 2006 and $27 million in 2005 and 2004. Decommissioning costs recovered from customers are deposited in external trusts.

I&M deposited an additional $4 million in 2006, 2005 and 2004 in its decommissioning trust for Cook Plant under funding provisions approved by regulatory commissions. At December 31, 2006, the total decommissioning trust fund balance for the Cook Plant was $974 million. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2006, fees and related interest of $247 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt and funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $274 million are recorded as part of Spent Nuclear Fuel and Decommissioning Trust on our Consolidated Balance Sheets. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

Trust Assets for Decommissioning and SNF Disposal

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the "Nuclear Trust Funds" section of Note 1, we record unrealized gains and losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at December 31:

	2006			2005		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Gross Unrealized Losses
	(in millions)					
Cash	$ 24	$ -	$ -	$ 21	$ -	$ -
Debt Securities	750	18	(8)	691	7	(7)
Equity Securities	474	192	(4)	422	148	(3)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,248	$ 210	$ (12)	$ 1,134	$ 155	$ (10)

Proceeds from sales of nuclear trust fund investments were $631 million, $706 million and $950 million in 2006, 2005 and 2004, respectively. Purchases of nuclear trust fund investments were $692 million, $761 million and $1,001 million in 2006, 2005 and 2004, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $7 million, $13 million and $13 million in 2006, 2005 and 2004, respectively. Gross realized losses including other-than-temporary impairments in 2006 from the sales of nuclear trust fund investments were $7 million, $17 million and $18 million in 2006, 2005 and 2004, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2006 is as follows:

	Fair Value (in millions)
Within 1 year	$ 50
1 year – 5 years	188
5 years – 10 years	215
After 10 years	297
Total	$ 750

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $38 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

In the event of an incident of a catastrophic nature, we are initially covered for the first $300 million through commercially available insurance. The next level of liability coverage of up to $10.8 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and under the Price-Anderson Act, we would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition could be adversely affected.

11. BUSINESS SEGMENTS

Our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio and Virginia continue to have commission-determined transition rates. Virginia is currently considering returning to regulation for generation. While our Utility Operations segment remains our primary business segment, the emergence of other areas of our business prompted us to identify two new business segments in 2006. One of these new segments is our MEMCO Operations segment, which reflects our significant ongoing barging activities. We also identified our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. We no longer consider Investments – Gas Operations and Investments – UK Operations as reportable segments because we have sold substantially all of those assets.

Starting in the fourth quarter of 2006, our new 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.

MEMCO Operations

- Bulk commodity barging operations.

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities in ERCOT.

The remainder of our company's activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the years ended December 31, 2006, 2005 and 2004 and balance sheet information as of December 31, 2006 and 2005. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's presentation.

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Year Ended December 31, 2006						
Revenues from:						
External Customers	$ 12,066	$ 520	$ 62	$ (26)	$ -	$ 12,622
Other Operating Segments	(55)	12	-	97	(54)	-
Total Revenues	$ 12,011	$ 532	$ 62	$ 71	$ (54)	$ 12,622
Depreciation and Amortization	$ 1,435	$ 11	$ 17	$ 4	$ -	$ 1,467
Interest Income	36	-	2	91	(68)	61
Interest Expense	667	4	11	118	(68)	732
Income Tax Expense (Credit)	543	42	(19)	(81)	-	485
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,028	$ 80	$ 12	$ (128)	$ -	$ 992
Discontinued Operations, Net of Tax	-	-	-	10	-	10
Net Income (Loss)	$ 1,028	$ 80	$ 12	$ (118)	$ -	$ 1,002
Gross Property Additions	$ 3,494	$ 7	$ 1	$ 26(b)	$ -	$ 3,528

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2005						
Revenues from:						
External Customers	$ 11,157	$ 344	$ 73	$ 537	$ -	$ 12,111
Other Operating Segments	232	11	-	(174)	(69)	-
Total Revenues	$ 11,389	$ 355	$ 73	$ 363	$ (69)	$ 12,111
Depreciation and Amortization	$ 1,315	$ 11	$ 17	$ 5	$ -	$ 1,348
Interest Income	31	-	2	80	(54)	59
Interest Expense	588	3	16	144	(54)	697
Income Tax Expense (Credit)	475	10	(28)	(27)	-	430
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,018	$ 21	$ 16	$ (26)	$ -	$ 1,029
Discontinued Operations, Net of Tax	-	-	-	27	-	27
Extraordinary Loss, Net of Tax	(225)	-	-	-	-	(225)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	-	-	-	(17)
Net Income	$ 776	$ 21	$ 16	$ 1	$ -	$ 814
Gross Property Additions	$ 2,755	$ 7	$ -	$ 2	$ -	$ 2,764

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2004						
Revenues from:						
External Customers	$ 10,620	272	90	3,263	-	14,245
Other Operating Segments	144	11	3	55	(213)	-
Total Revenues	$ 10,764	$ 283	$ 93	$ 3,318	$ (213)	$ 14,245
Depreciation and Amortization	$ 1,281	$ 11	$ 18	$ 14	$ -	$ 1,324
Interest Income	16	1	3	52	(39)	33
Interest Expense	621	3	15	181	(39)	781
Income Tax Expense (Credit)	558	5	18	(9)	-	572
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,175	$ 12	$ 73	$ (133)	$ -	$ 1,127
Discontinued Operations, Net of Tax	-	-	-	83	-	83
Extraordinary Loss, Net of Tax	(121)	-	-	-	-	(121)
Net Income (Loss)	$ 1,054	$ 12	$ 73	$ (50)	$ -	$ 1,089
Gross Property Additions	$ 1,471	$ 5	$ -	$ 161	$ -	$ 1,637

	Utility Operations	Nonutility Operations: MEMCO Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (c)	Consolidated
			(in millions)			
As of December 31, 2006						
Total Property, Plant and Equipment	$ 41,420	$ 239	$ 327	$ 35	$ -	$ 42,021
Accumulated Depreciation and Amortization	15,101	51	83	5	-	15,240
Total Property, Plant and Equipment – Net	$ 26,319	$ 188	$ 244	$ 30	$ -	$ 26,781
Total Assets	$ 36,632	$ 315	$ 342	$ 11,460	$ (10,762)	$ 37,987
Assets Held for Sale	44	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	42	-	-	42
As of December 31, 2005						
Total Property, Plant and Equipment	$ 38,283	$ 233	$ 327	$ 278	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	41	66	7	-	14,837
Total Property, Plant and Equipment – Net	$ 23,560	$ 192	$ 261	$ 271	$ -	$ 24,284
Total Assets	$ 34,344	$ 297	$ 396	$ 12,672	$ (11,537)	$ 36,172
Assets Held for Sale	44	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	40	12	-	52

(a) All Other includes:
- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Our UK operations, which were sold in 2004.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility.

(b) Gross Property Additions for All Other includes the $25 million acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines will be refurbished and transferred to a generating facility within our Utility Operations segment by the second half of 2008.

(c) 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.

12. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances.

Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects earnings. We recognize any hedge ineffectiveness in earnings immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Fair Value Hedging Strategies

Prior to the sale of HPL in the first quarter of 2005, to hedge the risks associated with our domestic gas pipeline and storage activities, we entered into natural gas derivative transactions to hedge natural gas inventory. The purpose of this hedging activity was to protect the natural gas inventory against changes in fair value due to changes in spot gas prices. The derivative transactions designated as fair value hedges of our natural gas inventory were MTM each month based upon changes in the NYMEX forward prices, whereas the natural gas inventory was MTM on a monthly basis based upon changes in the Gas Daily spot price at the end of the month. The differences between the indices used to MTM the natural gas inventory and the derivative transactions designated as fair value hedges can result in volatility in our reported net income. However, over time gains or losses on the sale of the natural gas inventory will be offset by gains or losses on the fair value hedges, resulting in the realization of gross margin we anticipated at the time the transaction was structured. In the third quarter of 2004, the gas-related fair value hedges were de-designated. As a result, the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy. During 2005 and 2004, we recognized a pretax loss of zero and approximately $27 million, respectively, in Revenues on our Consolidated Statements of Income related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Consolidated Statements of Income. During 2006, 2005 and 2004, we recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

At times we are exposed to foreign currency exchange rate risks primarily because we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The accumulated gains or losses related to our foreign currency hedges, which are immaterial, are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance

Sheets into Operating Expenses on our Consolidated Statements of Income over the same period as the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2006 and 2005, we reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, we reclassified an immaterial amount to earnings because the original forecasted transaction did not occur within the originally specified time period.

We enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2006, 2005 and 2004, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

We entered into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy. During 2005 and 2004, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2006 are:

	Hedging Assets (a)	Hedging Liabilities (a)	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings During the Next Twelve Months
		(in millions)		
Power	$ 30	$ (4)	$ 17	$ 17
Interest Rate	4	(4)	(23) (b)	(2)
Total	$ 34	$ (8)	$ (6)	$ 15

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.

(b) Includes $1 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2005 are:

	Hedging Assets (a)	Hedging Liabilities (a)	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings During the Next Twelve Months
	(in millions)			
Power and Gas	$ 11	$ 20	$ (6)	$ (5)
Interest Rate	3	-	(21) (b)	(2)
Total	$ 14	$ 20	$ (27)	$ (7)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.
(b) Includes $1 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2006, the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows related to forecasted transactions is forty-two-months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2006:

	Amount (in millions)
Balance at December 31, 2003	$ (94)
Changes in fair value	8
Reclasses from AOCI to net earnings	86
Balance at December 31, 2004	-
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(22)
Balance, at December 31, 2005	(27)
Changes in fair value	13
Reclasses from AOCI to net earnings	8
Balance at December 31, 2006	$ (6)

FINANCIAL INSTRUMENTS

The fair value of Long-term Debt is based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2006 and 2005 are summarized in the following tables.

	2006		2005	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 13,698	$ 13,743	$ 12,226	$ 12,416

13. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary loss and cumulative effect of accounting change as reported are as follows:

	Year Ended December 31, 2006	2005	2004
		(in millions)	
Federal:			
Current	$ 429	$ 375	$ 262
Deferred	5	28	263
Total	434	403	525
State and Local:			
Current	61	25	49
Deferred	(10)	4	(3)
Total	51	29	46
International:			
Current	-	(2)	1
Deferred	-	-	-
Total	-	(2)	1
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 485	$ 430	$ 572

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Year Ended December 31, 2006	2005	2004
		(in millions)	
Net Income	$ 1,002	$ 814	$ 1,089
Discontinued Operations (net of income tax of $(1) million, $(30) million and $75 million in 2006, 2005 and 2004, respectively)	(10)	(27)	(83)
Extraordinary Loss, (net of income tax of $(121) million and $(64) million in 2005 and 2004, respectively)	-	225	121
Cumulative Effect of Accounting Change (net of income tax of $(9) million in 2005)	-	17	-
Preferred Stock Dividends	3	7	6
Income Before Preferred Stock Dividends of Subsidiaries	995	1,036	1,133
Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	485	430	572
Pretax Income	$ 1,480	$ 1,466	$ 1,705
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 518	$ 513	$ 597
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	38	39	36
Investment Tax Credits, Net	(29)	(32)	(29)
Tax Effects of International Operations	-	(2)	1
Energy Production Credits	(19)	(18)	(16)
State Income Taxes	33	19	30
Removal Costs	(15)	(14)	(12)
AFUDC	(18)	(14)	(11)
Medicare Subsidy	(12)	(13)	(10)
Tax Reserve Adjustments	9	(11)	(14)
Other	(20)	(37)	-
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 485	$ 430	$ 572
Effective Income Tax Rate	32.8%	29.3%	33.5%

The following table shows elements of the net deferred tax liability and significant temporary differences.

	As of December 31, 2006	2005
	(in millions)	
Deferred Tax Assets	$ 2,384	$ 2,085
Deferred Tax Liabilities	(7,074)	(6,895)
Net Deferred Tax Liabilities	$ (4,690)	$ (4,810)
Property Related Temporary Differences	$ (3,292)	$ (3,301)
Amounts Due From Customers For Future Federal Income Taxes	(193)	(186)
Deferred State Income Taxes	(318)	(384)
Transition Regulatory Assets	(46)	(176)
Securitized Transition Assets	(809)	(232)
Regulatory Assets	(334)	(492)
Accrued Pensions	(155)	(345)
Deferred Income Taxes on Other Comprehensive Loss	120	14
All Other, Net	337	292
Net Deferred Tax Liabilities	$ (4,690)	$ (4,810)

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The IRS and other taxing authorities routinely examine our tax returns. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for years prior to 1997. We have reached a negotiated settlement of all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipate payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2006, we have total provisions for uncertain tax positions of approximately $32 million. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. We will continue to pursue credits for the next round of credits in 2009.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over eighty-four months in lieu of taking a depreciation deduction over twenty-years. This act also allows for the transfer ("poured-over") of funds held in nonqualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the nonqualified funds are poured-over; the funds are poured-over during the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for nonqualified funds. The tax law changes discussed in this paragraph have not materially affected our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. The application of these tax acts has not materially affected our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of $83 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. See "Ormet" section of Note 4 for further discussion. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes was approximately $4 million and $2 million for 2006 and 2005, respectively.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109. Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006, we recorded a net reduction to Deferred Income Taxes on our Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million was credited to Regulatory Assets based upon the related rate-making treatment.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. We believe the application of this act will not materially affect our results of operations, cash flows, or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect our results of operations, cash flows, or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provides a new alternative formula for deterring the research credit. The application of TRHCA 2006 is not expected to materially affect our results of operations, cash flows or financial condition.

14. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31, 2006	2005	2004
		(in millions)	
Net Lease Expense on Operating Leases	$ 340	$ 298	$ 308
Amortization of Capital Leases	64	57	54
Interest on Capital Leases	17	13	11
Total Lease Rental Costs	$ 421	$ 368	$ 373

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our Consolidated Balance Sheets.

	December 31, 2006	2005
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 94	$ 95
Distribution	15	15
Other	360	331
Construction Work in Progress	30	-
Total Property, Plant and Equipment Under Capital Leases	499	441
Accumulated Amortization	210	190
Net Property, Plant and Equipment Under Capital Leases	$ 289	$ 251
Obligations Under Capital Leases		
Noncurrent Liability	$ 210	$ 193
Liability Due Within One Year	81	58
Total Obligations Under Capital Leases	$ 291	$ 251

Future minimum lease payments consisted of the following at December 31, 2006:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2007	$ 90	$ 331
2008	68	312
2009	49	287
2010	28	260
2011	15	230
Later Years	126	1,893
Total Future Minimum Lease Payments	$ 376	$ 3,313
Less Estimated Interest Element	85	
Estimated Present Value of Future Minimum Lease Payments	$ 291	

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale and leaseback transaction as of December 31, 2006 are as follows:

	AEGCo	I&M
	(in millions)	
2007	$ 74	$ 74
2008	74	74
2009	74	74
2010	74	74
2011	74	74
Later Years	812	812
Total Future Minimum Lease Payments	$ 1,182	$ 1,182

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. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 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 railcar lease arrangements that do not utilize this type of financing structure.

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $51 million electric dragline for Sabine's mining operations. The initial capital outlay for the dragline was $26 million with an additional estimated $25 million of transportation, assembly and upgrade costs to be incurred prior to the completion date of mid-2008. These additional costs will be added to our consolidated lease assets and capital lease obligations as they are incurred. Sabine will pay interim rent on a quarterly basis starting in March 2007 and continue through the completion date of mid-2008. Once the dragline is fully assembled, Sabine will pay capital and interest payments on the outstanding lease obligation. At December 31, 2006, the capital lease asset is included in Construction Work in Progress and the capital lease obligation is included in Noncurrent Liabilities – Deferred Credits and Other on our 2006 Consolidated Balance Sheet. We calculated future payments using both interim rent prior to completion and capital and interest from completion until the maturity of the lease solely using the initial capital outlay of $26 million.

15. FINANCING ACTIVITIES

Common Stock

Common Stock Repurchase

In February 2005, our Board of Directors authorized the repurchase of up to $500 million of our common stock from time to time through 2006. In March 2005, we purchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May 2005 and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged $34.18 per share. Management has not established a timeline for the buyback of the remaining stock under this plan.

Equity Units and Remarketing of Senior Notes

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consisted of a forward purchase contract and a senior note. In June 2005, we remarketed and settled $345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes mature on August 16, 2007. We did not receive any proceeds from the mandatory remarketing.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for $50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 1, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

We issued 2.3 million, 1.9 million and 0.5 million shares of common stock in connection with our stock option plan during 2006, 2005 and 2004, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2006, 2005 and 2004:

Shares of Common Stock	Issued	Held in Treasury
Balance, January 1, 2004	404,016,413	8,999,992
Issued	841,732	-
Balance, December 31, 2004	404,858,145	8,999,992
Issued	10,360,685	-
Treasury Stock Acquisition	-	12,500,000
Balance, December 31, 2005	415,218,830	21,499,992
Issued	2,955,898	-
Balance, December 31, 2006	418,174,728	21,499,992

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2006			
	Call Price Per Share (a)	**Shares Authorized (b)**	**Shares Outstanding (c)**	**Amount (in millions)**
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,044	$ 61

	December 31, 2005			
	Call Price Per Share (a)	**Shares Authorized (b)**	**Shares Outstanding (c)**	**Amount (in millions)**
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	607,642	$ 61

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.

(b) As of December 31, 2006, the subsidiaries had 14,487,993 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,366 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2005, the subsidiaries had 14,487,597 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued.

(c) The number of shares of preferred stock redeemed is 598 shares in 2006, 664,470 shares in 2005 and 96,378 shares in 2004.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2006	Interest Rate Range at December 31, 2006	2005	December 31, 2006	2005
				(in millions)	
SENIOR UNSECURED NOTES (a)					
2006-2011	5.11%	3.60%-6.91%	3.60%-6.91%	$ 3,085	$ 3,529
2012-2017	5.41%	4.85%-6.375%	4.85%-6.375%	2,793	2,568
2032-2037	6.20%	5.625%-6.65%	5.625%-6.65%	2,775	2,125
POLLUTION CONTROL BONDS (b)					
2006-2011	4.12%	3.60%-4.90%	2.70%-4.55%	181	204
2014-2024	4.28%	3.50%-6.05%	2.625%-6.10%	811	794
2025-2038	4.06%	3.53%-6.125%	2.625%-6.55%	958	937
NOTES PAYABLE (c)					
2006-2017	6.86%	4.47%-9.60%	4.47%-15.25%	337	904
SECURITIZATION BONDS (d)					
2008-2021	5.32%	4.98%-6.25%	5.01%-6.25%	2,335	648
FIRST MORTGAGE BONDS (e)					
2006-2008 (f)	7.07%	7.00%-7.75%	6.20%-7.75%	117	222
NOTES PAYABLE TO TRUST					
2043	5.25%	5.25%	5.25%	113	113
SPENT NUCLEAR FUEL OBLIGATION (g)				247	236
OTHER LONG-TERM DEBT (h)					
2026	13.718%	13.718%	13.718%	2	4
Unamortized Discount (net)				(56)	(58)
Total Long-term Debt Outstanding				13,698	12,226
Less Portion Due Within One Year				1,269	1,153
Long-term Portion				$ 12,429	$ 11,073

(a) Certain senior unsecured notes have been adjusted for MTM of Fair Value Hedges associated with the debt.

(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued $1.7 billion in securitization bonds with interest rates ranging from 4.98% to 5.3063% and final maturity dates ranging from January 2012 to July 2021. Scheduled final payment dates range from January 2010 to July 2020. TFII is the sole owner of the transition charges and the original transition property. The holders of the securitization bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.

(e) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment. There are certain limitations on establishing additional liens against our assets under our indentures.

(f) 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 balances of $19 million in 2006 and 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments and $21 million are included in Other Noncurrent Assets on our Consolidated Balance Sheets at December 31, 2006 and 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 has a balance of $8 million at December 31, 2006 and 2005. Trust fund assets related to this obligation of $9 million and $1 million at December 31, 2006 and 2005, respectively, are included in Other Temporary Cash Investments and $8 million is included in Other Noncurrent Assets on our Consolidated Balance Sheets at December 31, 2005. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(g) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 10).

(h) Other long-term debt consists of a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2006 IS PAYABLE AS FOLLOWS:

	2007	2008	2009	2010	2011	After 2011	Total
				(in millions)			
Principal Amount	$ 1,269	$ 650	$ 485	$ 1,315	$ 596	$ 9,439	$ 13,754
Unamortized Discount							(56)
Total Long-term Debt Outstanding at December 31, 2006							$ 13,698

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on our Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2006 and 2005, is included in Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2006 and 2005, are reported as Notes Payable to Trust within Long-term Debt.

The business trust is treated as a nonconsolidated subsidiary of SWEPCo. The only asset of the business trust is the subordinated debentures issued by SWEPCo as specified above. In addition to the obligations under the subordinated debentures, SWEPCo also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit and Short-term Debt – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a 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 December 31, 2006, we had credit facilities totaling $3 billion to support our commercial paper program. As of December 31, 2006, AEP's commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program the maximum amount of commercial paper outstanding during the year was $325 million in March 2006 and the weighted average interest rate of commercial paper outstanding during the year was 4.96%. Our outstanding short-term debt was as follows:

	At December 31, 2006		At December 31, 2005	
	Outstanding Amount	Interest Rate	Outstanding Amount	Interest Rate
Type of Debt	(in millions)		(in millions)	
Commercial Paper – JMG (a)	$ 1	5.56 %	$ 10	4.47 %
Line of Credit – Sabine	17	6.38 %	-	-
Total	$ 18		$ 10	

(a) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires on August 24, 2007. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit also purchases accounts receivable from KGPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2006	2005	2004
	($ in millions)		
Proceeds from Sale of Accounts Receivable	$ 6,849	$ 5,925	$ 5,163
Loss on Sale of Accounts Receivable	$ 31	$ 18	$ 7
Average Variable Discount Rate	5.02%	3.23%	1.50%

	December 31, 2006	2005
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 87	$ 106
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	85	103
Retained Interest if 20% Adverse Change in Uncollectible Accounts	83	101

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2006	Face Value December 31, 2005
	(in millions)	
Customer Accounts Receivable Retained	$ 676	$ 826
Accrued Unbilled Revenues Retained	350	374
Miscellaneous Accounts Receivable Retained	44	51
Allowance for Uncollectible Accounts Retained	(30)	(31)
Total Net Balance Sheet Accounts Receivable	1,040	1,220
Customer Accounts Receivable Securitized	536	516
Total Accounts Receivable Managed	$ 1,576	$ 1,736
Net Uncollectible Accounts Written Off	$ 31	$ 74

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $29 million and $30 million at December 31, 2006 and 2005, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

16. STOCK-BASED COMPENSATION

As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) 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 LTIP in 2000 and the amended and restated version in 2005. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used options in limited circumstances totaling 149,000 options in 2004, 10,000 options in 2005 and none during 2006. The following sections provide further information regarding each type of stock-based compensation award granted by the Board of Directors.

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

Stock Options

For all stock options granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Stock options were granted with a ten-year term and generally vested, 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 LTIP 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, we converted all CSW stock options outstanding into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. We adjusted the exercise price for each CSW stock option for the exchange ratio. No CSW stock options remained outstanding as of December 31, 2006. The remaining stock options were exercised in the fourth quarter of 2006.

The total fair value of stock options vested and the total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 are as follows:

Stock Options		2006		2005		2004
			(in thousands)			
Fair Value of Stock Options Vested	$	3,667	$	5,036	$	14,504
Intrinsic Value of Options Exercised (a)		16,823		12,091		3,182

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2006, 2005 and 2004 is as follows:

	2006			2005			2004		
	Options		Weighted Average Exercise Price	Options		Weighted Average Exercise Price	Options		Weighted Average Exercise Price
	(in thousands)			(in thousands)			(in thousands)		
Outstanding at January 1,	6,222	$	34.16	8,230	$	33.29	9,095	$	33.03
Granted	-		N/A	10		38.65	149		30.76
Exercised/Converted	(2,343)		33.12	(1,886)		36.94	(525)		27.10
Forfeited/Expired	(209)		41.58	(132)		31.97	(489)		34.33
Outstanding at December 31,	3,670		34.41	6,222		34.16	8,230		33.29
Options Exercisable at December 31,	3,411	$	34.83	5,199	$	35.40	6,069	$	35.05
Weighted average exercise price of options:									
Granted above Market Price			N/A			N/A			N/A
Granted at Market Price			N/A		$	38.65		$	30.76

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

Options Outstanding

2006 Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life		Weighted Average Exercise Price		Aggregate Intrinsic Value
	(in thousands)	(in years)				(in thousands)
$25.73 - $27.95	902	6.07	$	27.45	$	13,651
$30.76 - $38.65	2,401	3.29		35.34		17,392
$43.79 - $49.00	367	4.39		45.43		-
Total (a)	3,670	4.08		34.41	$	31,043

(a) Options outstanding are not significantly different from the number of shares expected to vest.

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

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable	Weighted Average Remaining Life		Weighted Average Exercise Price		Aggregate Intrinsic Value
	(in thousands)	(in years)				(in thousands)
$25.73 - $27.95	702	5.83	$	27.32	$	10,715
$30.76 - $35.63	2,342	3.19		35.42		16,766
$43.79 - $49.00	367	4.39		45.43		-
Total	3,411	3.86		34.83	$	27,481

We include the proceeds received from exercised stock options in common stock and paid-in capital. For options granted through December 31, 2006, we estimated the grant date fair value of each option award using a Black-Scholes option-pricing model with weighted average assumptions. We estimated expected volatilities using the historical monthly volatility of our common stock for the thirty-six-month period prior to each grant. We also assumed a seven-year average expected term. 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.

We used the following weighted average assumptions to estimate the fair value of AEP stock options granted in 2005 and 2004. No stock options were granted in 2006.

	2006	2005	2004
Risk Free Interest Rate	N/A	4.14%	4.14%
Expected Volatility	N/A	24.63%	28.17%
Expected Dividend Yield	N/A	4.00%	4.84%
Expected Life	N/A	7 years	7 years
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	N/A
Granted at Market Price	N/A	$ 7.60	$ 6.06

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 AEP Career Shares, a form of phantom stock units, 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, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, for both the performance units and AEP Career Shares is adjusted for changes in value. 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. The vesting period of all performance units is three years.

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2006, 2005 and 2004 as follows:

Performance Units	2006	2005	2004
Awarded Units (in thousands)	1,635	1,013	119
Weighted Average Unit Fair Value at Grant Date	$ 39.75	$ 34.02 (a)	$ 30.76 (a)
Vesting Period (years)	3	3	3

(a) The unit fair value is the actual value at the grant date because there was only one award in that period.

Performance Units and AEP Career Shares (Reinvested Dividends Portion)			
Awarded Units (in thousands)	118	89	61
Weighted Average Grant Date Fair Value	$ 36.87	$ 36.25	$ 32.92
Vesting Period (years)	(a)	(a)	(a)

(a) Vesting Period (years) range from 0 to 3 years. The Vesting Period of the reinvested dividends is equal to the remaining life of the related performance units and AEP Career Shares.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance 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. In January 2006, the HR Committee certified a performance score for the three-year period ended December 31, 2005 of 49%. 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 certified performance score for the three-year performance period ended December 31, 2004 was 0%.

Due to the anticipated 2004 CEO succession, on December 10, 2003 the HR Committee made performance unit grants for the shortened performance period of December 10, 2003 through December 31, 2004. No performance period ended on December 31, 2006 because this performance period was shorter than the normal three-year period used by us and there were no other performance unit grants in 2003. In 2005, the HR Committee certified a performance factor of 123.1% for performance units granted on December 10, 2003 and 946,789 performance units were mandatorily deferred into AEP stock units, of which 917,032 units vested on December 31, 2006 and the remainder were forfeited due to participant terminations. These stock units have the same value, dividend rights, vesting and accounting treatment as the performance units that gave rise to them, except that they are no longer subject to performance measures.

The cash payouts for the years ended December 31, 2006, 2005 and 2004 were as follows:

	2006	2005	2004
		(in thousands)	
Cash Payouts for Performance Units	$ 2,630	$ -	$ -
Cash Payouts for AEP Career Share Distributions	1,079	1,373	673

Restricted Shares and Restricted Stock Units

Our Board of Directors 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. 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 shares granted by the grant date market price of $30.76. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on our restricted shares are paid in cash.

Our Board of Directors may also grant restricted stock units (RSUs), 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 RSUs accrue as additional RSUs and 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 RSUs is six years.

In January 2006, our Board of Directors also granted RSUs with performance vesting conditions to certain employees who are integral to our project to design and build proposed IGCC power plants. 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.

Our Board of Directors awarded RSUs, including units awarded for dividends, for the years ended December 31, 2006, 2005 and 2004 as follows:

Restricted Stock Units	2006	2005	2004
Awarded Units (in thousands)	65	166	106
Weighted Average Grant Date Fair Value	$ 37.47	$ 35.67	$ 32.03

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2006, 2005 and 2004 were as follows:

Restricted Shares and Restricted Stock Units	2006	2005	2004
		(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 3,939	$ 3,087	$ 577
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	4,686	3,703	809

(a) Intrinsic value is calculated as market price.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2006, and changes during the year ended December 31, 2006 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2006	497	$ 32.19
Granted	65	37.47
Vested	(129)	30.63
Forfeited	(25)	35.72
Nonvested at December 31, 2006	408	33.31

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2006 was $17 million and the weighted average remaining contractual life was 2.74 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-Employee Directors providing each nonemployee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The Non-Employee Directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

The compensation cost for stock units is recorded when the units are awarded, and the liability is adjusted for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2006, 2005 and 2004.

Our Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2006, 2005 and 2004 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	2006	2005	2004
Awarded Units (in thousands)	33	27	30
Weighted Average Grant Date Fair Value	$ 36.66	$ 36.74	$ 32.81

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2006, 2005 and 2004 were as follows:

Share-based Compensation Plans	2006	2005	2004
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 45,842	$ 28,660	$ 19,721
Actual Tax Benefit Realized	16,045	10,031	6,902
Total Compensation Cost Capitalized	10,953	5,113	3,518

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.

During the years ended December 31, 2006, 2005 and 2004, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2006, there was $90 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. 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 1.64 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2006, 2005 and 2004 were as follows:

Share-based Compensation Plans	2006	2005	2004
	(in thousands)		
Cash received from stock options exercised	$ 77,534	$ 57,546	$ 14,250
Actual tax benefit realized for the tax deductions from stock options exercised	5,825	4,235	1,107

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU 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 LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

17. PROPERTY, PLANT AND EQUIPMENT

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

2006	Regulated					Nonregulated				
Functional Class of Property	**Property, Plant and Equipment**		**Accumulated Depreciation**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Property, Plant and Equipment**		**Accumulated Depreciation**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
	(in millions)			**(%)**	**(in years)**	**(in millions)**			**(%)**	**(in years)**
Production	$ 7,892	$	4,437	2.6 – 3.8	30 - 121	$ 8,895	$	3,886	2.57 – 9.15	20 - 121
Transmission	7,018		2,332	1.6 - 2.9	25 - 87	-		-	N.M.	N.M.
Distribution	11,338		3,121	3.0 - 4.0	11 - 75	-		-	N.M.	N.M.
CWIP	1,423		(41)	N.M.	N.M.	2,050		2	N.M.	N.M.
Other	2,400		1,067	6.7 – 11.5	24 - 55	1,005		436	N.M.	N.M.
Total	$ 30,071	$	10,916			$ 11,950	$	4,324		

2005	Regulated					Nonregulated				
Functional Class of Property	**Property, Plant and Equipment**		**Accumulated Depreciation**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Property, Plant and Equipment**		**Accumulated Depreciation**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
	(in millions)			**(%)**	**(in years)**	**(in millions)**			**(%)**	**(in years)**
Production	$ 7,411	$	4,166	2.7 - 3.8	30 - 120	$ 9,095	$	4,019	2.6 - 3.3	20 - 120
Transmission	6,433		2,280	1.7 - 3.0	25 - 75	-		-	N.M.	N.M.
Distribution	10,702		3,085	3.1 - 4.1	10 - 75	-		-	N.M.	N.M.
CWIP	1,341		(14)	N.M.	N.M.	876		(3)	N.M.	N.M.
Other	2,266		992	5.1 - 16.0	N.M.	997		312	2.0 - 4.9	2 - 37
Total	$ 28,153	$	10,509			$ 10,968	$	4,328		

2004	Regulated		Nonregulated	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
	(%)	**(in years)**	**(%)**	**(in years)**
Production	2.7 - 3.8	30 - 120	2.6 - 3.9	20 - 120
Transmission	1.7 - 3.0	25 - 75	N.M.	N.M.
Distribution	3.2 - 4.1	10 - 75	N.M.	N.M.
Other	5.4 - 16.4	N.M.	2.0 – 14.2	0 - 50

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.66, $0.66 and $0.65 per ton in 2006, 2005 and 2004, respectively.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see "Accounting for Asset Retirement Obligations (ARO)" section of this note).

Accounting for Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

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

We completed a review of our FIN 47 conditional ARO during the fourth quarter of 2005 and concluded that we have legal liabilities for asbestos removal and disposal in general buildings and generating plants. In 2005, we recorded $55 million of conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to regulatory liability. Of the $55 million, we recorded an unfavorable cumulative effect of $26 million ($17 million, net of tax) for our nonregulated generation operations related to asbestos removal in the Utility Operations segment.

We have legal obligations for asbestos removal and for the retirement of certain ash ponds, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. As of December 31, 2006 and 2005, our ARO liability was $1,028 million and $946 million, respectively, and included $803 million and $731 million for nuclear decommissioning of the Cook Plant. As of December 31, 2006 and 2005, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $974 million and $870 million, respectively, relating to the Cook Plant and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

Pro forma net income and earnings per share are not presented for the year ended December 31, 2004 because the pro forma application of FIN 47 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods. As of December 31, 2004, the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted at the beginning of each period was $52 million.

The following is a reconciliation of the 2005 and 2006 aggregate carrying amounts of ARO:

	Amount (in millions)
ARO at January 1, 2005, Including Held for Sale	$ 1,076
Accretion Expense	63
Liabilities Incurred (a)	76
Liabilities Settled	(4)
Revisions in Cash Flow Estimates	(9)
Less ARO Liability for:	
South Texas Project (b)	(256)
ARO at December 31, 2005 (c)	946
Accretion Expense	63
Liabilities Incurred	9
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	30
ARO at December 31, 2006 (d)	$ 1,028

(a) Includes $55 million of ARO relating to the adoption of FIN 47.
(b) The ARO related to nuclear decommissioning costs for TCC's share of STP was transferred to the buyer in connection with the May 2005 sale (see "Dispositions" section of Note 8).
(c) The current portion of our ARO, totaling $10 million, is included in Other in the Current Liabilities section of our 2005 Consolidated Balance Sheet.
(d) The current portion of our ARO, totaling $5 million is included in Other in the Current Liabilities section of our 2006 Consolidated Balance Sheet.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The amounts of AFUDC were $30.2 million, $20.9 million and $14.5 million in 2006, 2005 and 2004, respectively, and are included in Allowance For Equity Funds Used During Construction on our Consolidated Statements of Income. The amounts of interest capitalized and allowance for borrowed funds used during construction were $82.3 million, $35.6 million and $22.4 million in 2006, 2005 and 2004, respectively, and are included in Interest Expense on our Consolidated Statements of Income.

Jointly-owned Electric Utility Plant

We have generating units that are jointly-owned with nonaffiliated companies. We are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2006		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress (h)**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 16	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85	32	49
J.M. Stuart Generating Station (c)	Coal	26.0	284	102	128
Wm. H. Zimmer Generating Station (a)	Coal	25.4	751	5	302
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	240	5	167
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	97	2	57
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	481	5	310
Oklaunion Generating Station (Unit No. 1) (f)	Coal	78.1	417	3	200
Transmission	N/A	(g)	63	-	42

			Company's Share at December 31, 2005		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress (h)**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 16	$ -	$ 7
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85	8	48
J.M. Stuart Generating Station (c)	Coal	26.0	266	35	121
Wm. H. Zimmer Generating Station (a)	Coal	25.4	749	2	280
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	238	4	160
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	94	2	55
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	460	10	298
Oklaunion Generating Station (Unit No. 1) (f)	Coal	78.1	415	3	192
Transmission	N/A	(g)	63	1	41

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by Cleco Corporation, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) TCC's 7.8% interest in Oklaunion Generating Station amounted to $40 million at December 31, 2006 and 2005. These amounts are included in Assets Held for Sale on our Consolidated Balance Sheets. Oklaunion Generating Station is operated by PSO.
(g) Varying percentages of ownership.
(h) Primarily relates to environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2006 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	**March 31**	**June 30**	**September 30**	**December 31**
Revenues	$ 3,108	$ 2,936	$ 3,594	$ 2,984
Operating Income	689	371	535	371
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	378	172	265	177
Net Income	381	175	265	181
Basic Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.96	0.44	0.67	0.45
Earnings per Share	0.97	0.44	0.67	0.46
Diluted Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (e)	0.95	0.43	0.67	0.44
Earnings per Share	0.96	0.44	0.67	0.46

	2005 Quarterly Periods Ended			
(In Millions – Except Per Share Amounts)	**March 31**	**June 30**	**September 30**	**December 31**
Revenues	$ 3,065	$ 2,819	$ 3,328	$ 2,899
Operating Income	660	455	624	188
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	354	218	365	92
Extraordinary Loss, Net of Tax (a)	-	-	-	(225)
Net Income (Loss)	355	221	387	(149)
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share	0.90	0.58	0.99	(0.38)
Diluted Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (c)	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share (d)	0.90	0.58	0.99	(0.38)

(a) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarter of 2005.

(b) Amounts for 2005 do not add to $(0.58) for Extraordinary Loss per Share due to differences between the weighted average number of shares outstanding for the fourth quarter of 2005 and the year 2005.

(c) Amounts for 2005 do not add to $2.63 for Diluted Earnings (Loss) per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.

(d) Amounts for 2005 do not add to $2.08 for Diluted Earnings (Loss) per Share due to rounding.

(e) Amounts for the quarter ended December 31, 2006 do not add to $2.50 for Diluted Earnings (Loss) per Share Before Discontinued Operations due to rounding.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 309,814	$ 270,755	$ 241,788	$ 233,165	$ 213,281
Operating Income	$ 12,918	$ 10,901	$ 10,130	$ 8,456	$ 7,511
Net Income	$ 10,914	$ 8,695	$ 7,842	$ 7,964	$ 7,552
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 704,434	$ 699,342	$ 692,841	$ 674,174	$ 652,332
Accumulated Depreciation and Amortization	398,422	382,925	368,484	351,062	330,187
Net Property, Plant and Equipment	$ 306,012	$ 316,417	$ 324,357	$ 323,112	$ 322,145
Total Assets	$ 393,331	$ 376,703	$ 376,393	$ 380,045	$ 377,716
Common Shareholder's Equity	$ 55,376	$ 50,472	$ 48,671	$ 45,875	$ 42,597
Long-term Debt (a)	$ 44,837	$ 44,828	$ 44,820	$ 44,811	$ 44,802
Obligations Under Capital Leases (a)	$ 12,001	$ 12,227	$ 12,474(b)	$ 269	$ 501

(a) Including portion due within one year.
(b) Increased primarily due to a new coal transportation lease. See Note 14.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of Unit 1 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 operates and co-owns Unit 1 of the Rockport Plant. Unit 2 of the Rockport Plant is owned by a third party and leased to I&M and us. See Off-Balance Sheet Arrangements below.

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 through December 2022. Under the terms of its unit power agreement, I&M agreed to purchase all of our Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo.

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. The co-owners divide the costs of operating the plant.

Results of Operations

Net Income increased $2.2 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 calculated and adjusted monthly for over/under billings.

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Net Income
(in millions)

Year Ended December 31, 2005		$ 8.7
Change in Gross Margin:		
Wholesale Sales		0.5
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	0.8	
Depreciation and Amortization	0.1	
Taxes Other Than Income Taxes	0.6	
Other Income (Expense)	(0.1)	
Interest Expense	(0.5)	
Total Change in Operating Expenses and Other		0.9
Income Tax Credit		0.8
Year Ended December 31, 2006		$ 10.9

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $0.5 million primarily due to higher earnings on increased plant and capital investment.

Other Operation and Maintenance expenses decreased $0.8 million primarily due to decreased maintenance cost reflecting less planned and forced outages at the Rockport Plant in 2006 than 2005.

Taxes Other Than Income Taxes decreased $0.6 million primarily due to lower real and personal property taxes as the prior year accrual was adjusted to the actual amount paid.

Interest Expense increased $0.5 million primarily due to increased rates on short-term borrowing and higher borrowed amounts.

Income Taxes

Income Tax Credit increased $0.8 million primarily due to the recording of tax return adjustments and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by an increase in pretax book income.

Off-Balance Sheet Arrangements

Rockport Plant Unit 2

In 1989, we, along with I&M, entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (Rockport 2). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. Neither we, nor I&M or AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

We deferred the gain from the sale and amortize it over the term of the lease, which expires in 2022. The Owner Trustee owns Rockport 2 and leases it to I&M and us. We account for the lease as an operating lease with the payment obligations included in the lease footnote (see Note 14). Our future minimum lease payments are $1.2 billion as of December 31, 2006. The lease term is for 33 years with potential renewal options. At the end of the lease term, we, along with I&M, have the option to renew the lease or the Owner Trustee can sell Rockport 2.

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments due by Period
(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Advances from Affiliates (a)	$ 53.6	$ -	$ -	$ -	$ 53.6
Interest on Long-term Debt (b)	2.0	4.0	4.0	26.0	36.0
Fixed Rate Portion of Long-term Debt (c)	-	-	45.0	-	45.0
Capital Lease Obligations (d)	1.0	2.0	1.9	16.1	21.0
Noncancelable Operating Leases (d)	77.3	154.7	153.9	814.5	1,200.4
Construction Contracts for Capital Assets (e)	96.3	-	-	-	96.3
Total	$ 230.2	$ 160.7	$ 204.8	$ 856.6	$ 1,452.3

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 14.
(e) Represents only capital assets that are contractual obligations.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

Significant Factors

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

Plant Acquisition – Lawrenceburg Generating Station

In January 2007, we agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from Public Service Enterprise Group for approximately $325 million and to assume liabilities of approximately $2 million. We expect to complete the transaction in the second quarter of 2007 after receipt of regulatory approvals. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant. The combined-cycle, natural gas power plant has a generating capacity of 1,096 MW. This new generation acquisition will be financed by a capital contribution from AEP and issuance of debt related to this acquisition.

Critical Accounting Estimates

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

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING REVENUES	$ 309,814	$ 270,755	$ 241,788
EXPENSES			
Fuel for Electric Generation	178,654	140,077	112,470
Rent – Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	12,808	11,902	10,998
Maintenance	9,776	11,518	12,152
Depreciation and Amortization	23,911	24,009	23,579
Taxes Other Than Income Taxes	3,464	4,065	4,176
TOTAL	296,896	259,854	231,658
OPERATING INCOME	12,918	10,901	10,130
Other Income (Expense):			
Interest Income	-	24	-
Allowance for Equity Funds Used During Construction	24	98	42
Interest Expense	(2,947)	(2,437)	(2,446)
INCOME BEFORE INCOME TAXES	9,995	8,586	7,726
Income Tax Credit	(919)	(109)	(116)
NET INCOME	$ 10,914	$ 8,695	$ 7,842

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
BALANCE AT BEGINNING OF PERIOD	$ 26,038	$ 24,237	$ 21,441
Net Income	10,914	8,695	7,842
Cash Dividends Declared	6,010	6,894	5,046
BALANCE AT END OF PERIOD	$ 30,942	$ 26,038	$ 24,237

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

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

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

	2006	2005
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	$ 31,060	$ 29,671
Fuel	37,701	14,897
Materials and Supplies	7,873	7,017
Accrued Tax Benefits	3,808	2,074
Prepayments and Other	57	9
TOTAL	80,499	53,668
PROPERTY, PLANT AND EQUIPMENT		
Electric – Production	686,776	684,721
Other	2,460	2,369
Construction Work in Progress	15,198	12,252
Total	704,434	699,342
Accumulated Depreciation and Amortization	398,422	382,925
TOTAL – NET	306,012	316,417
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,438	5,572
Deferred Charges and Other	1,382	1,046
TOTAL	6,820	6,618
TOTAL ASSETS	$ 393,331	$ 376,703

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

AEP GENERATING COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2006 and 2005

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 53,646	$ 35,131
Accounts Payable:		
General	549	926
Affiliated Companies	27,935	22,161
Long-term Debt Due Within One Year – Nonaffiliated	-	44,828
Accrued Taxes	3,685	3,055
Accrued Rent – Rockport Plant Unit 2	4,963	4,963
Other	1,200	1,228
TOTAL	91,978	112,292
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	44,837	-
Deferred Income Taxes	19,749	23,617
Regulatory Liabilities and Deferred Investment Tax Credits	79,650	82,689
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	88,762	94,333
Deferred Credits and Other	12,979	13,300
TOTAL	245,977	213,939
TOTAL LIABILITIES	337,955	326,231
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $1,000 Per Share:		
Authorized – 1,000 Shares		
Outstanding – 1,000 Shares	1,000	1,000
Paid-in Capital	23,434	23,434
Retained Earnings	30,942	26,038
TOTAL	55,376	50,472
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 393,331	$ 376,703

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

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 10,914	$ 8,695	$ 7,842
Adjustments for Noncash Items:			
Depreciation and Amortization	23,911	24,009	23,579
Deferred Income Taxes	(6,730)	(1,666)	(2,219)
Deferred Investment Tax Credits	(3,433)	(3,532)	(3,339)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Change in Other Noncurrent Assets	(3,295)	(654)	3,266
Change in Other Noncurrent Liabilities	3,169	2,204	(2,511)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(1,389)	(6,593)	1,670
Fuel, Materials and Supplies	(23,660)	452	3,192
Accounts Payable	5,397	4,739	1,939
Accrued Taxes, Net	(1,104)	(7,825)	2,736
Other Current Assets	(48)	(9)	-
Other Current Liabilities	(28)	34	196
Net Cash Flows From (Used For) Operating Activities	(1,867)	14,283	30,780
INVESTING ACTIVITIES			
Construction Expenditures	(10,403)	(15,372)	(15,757)
Proceeds from Sales of Assets	75	-	-
Net Cash Flows Used For Investing Activities	(10,328)	(15,372)	(15,757)
FINANCING ACTIVITIES			
Change in Advances from Affiliates, Net	18,515	8,216	(9,977)
Principal Payments for Capital Lease Obligations	(310)	(233)	-
Dividends Paid on Common Stock	(6,010)	(6,894)	(5,046)
Net Cash Flows From (Used For) Financing Activities	12,195	1,089	(15,023)
Net Change in Cash and Cash Equivalents	-	-	-
Cash and Cash Equivalents at Beginning of Period	-	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -	$ -
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 2,597	$ 2,170	$ 2,179
Net Cash Paid for Income Taxes	10,149	13,435	542
Noncash Acquisitions Under Capital Leases	84	45	12,297

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Generating Company:

We have audited the accompanying balance sheets of AEP Generating Company (the “Company”) as of December 31, 2006 and 2005, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 664,664	$ 793,246	$ 1,212,849	$ 1,797,686	$ 1,739,853
Operating Income	$ 129,097	$ 177,281	$ 244,081	$ 452,966	$ 541,132
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	$ 41,569	$ 50,772	$ 294,656	$ 217,547	$ 275,941
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	-	(224,551)	(120,534)	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	122	-
Net Income (Loss)	$ 41,569	$ (173,779)	$ 174,122	$ 217,669	$ 275,941
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 2,870,032	$ 2,657,195	$ 2,495,921	$ 2,428,004	$ 2,338,100
Accumulated Depreciation and Amortization	630,239	636,078	726,771	697,023	663,266
Net Property, Plant and Equipment	$ 2,239,793	$ 2,021,117	$ 1,769,150	$ 1,730,981	$ 1,674,834
Total Assets	$ 5,323,731	$ 4,904,912	$ 5,678,320	$ 5,820,360	$ 5,565,599
Common Shareholder's Equity	$ 405,116	$ 947,630	$ 1,268,643	$ 1,209,049	$ 1,101,134
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 5,921	$ 5,940	$ 5,940	$ 5,940	$ 5,942
Trust Preferred Securities	$ -	$ -	$ -	$ -	$ 136,250
Long-term Debt (b)	$ 3,015,614 (c)	$ 1,853,496	$ 1,907,294	$ 2,291,625	$ 1,438,565
Obligations Under Capital Leases (b)	$ 4,097	$ 1,378	$ 880	$ 1,043	$ -

(a) See "Extraordinary Items" section of Note 2 and "TCC Texas Restructuring" section of Note 4.
(b) Including portion due within one year.
(c) Increased due to issuance of securitization bonds in October 2006. See Note 15.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As a public utility, we engage in the transmission and distribution of electric power to 738,000 retail customers through REPs in our service territory in southern and central Texas. We consolidate AEP Texas Central Transition Funding LLC and AEP Texas Central Transition Funding II LLC, our wholly-owned subsidiaries.

Under the Texas Restructuring Legislation, we completed the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture, 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, we sought and received FERC approval to be removed from those agreements. Our sharing of margins under the CSW Operating Agreement ceased on May 1, 2006. The sharing of margins with AEP East companies under the SIA ceased on April 1, 2006. These trading and marketing margins affected our results of operations and cash flows.

Prior to May 1, 2006, as a member of the CSW Operating Agreement, we were compensated for energy delivered to other members based upon our incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies were generally shared among the members based upon the relative magnitude of the energy each member provided to make such sales.

Prior to April 1, 2006, under the SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities were shared among AEP East companies and AEP West companies. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Extraordinary Loss
(in millions)

Year Ended December 31, 2005		$ 51
Changes in Gross Margin:		
Off-system Sales	(125)	
Texas Wires	17	
Transmission Revenues	(12)	
Other	23	
Total Change in Gross Margin		(97)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	58	
Depreciation and Amortization	(18)	
Taxes Other Than Income Taxes	9	
Carrying Costs Income	88	
Other Income	(7)	
Interest Expense	(32)	
Total Change in Operating Expenses and Other		98
Income Tax Expense		(10)
Year Ended December 31, 2006		$ 42

Income Before Extraordinary Loss decreased $9 million primarily due to a decrease in Gross Margin of $97 million and a $10 million increase in Income Tax Expense, partially offset by a decrease in Operating Expenses and Other of $98 million. We substantially exited the generation market with the sale of STP in May 2005.

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

- Margins from Off-system Sales decreased $125 million primarily due to the sale of STP, which resulted in lower revenues of $74 million and a $36 million adjustment to the provision for refund primarily due to the fuel reconciliation adjustment in 2005. An additional $17 million decrease was primarily due to a decrease in our allocation of off-system sales margins under the SIA. As of May 1, 2006, we no longer share off-system sales margins under the SIA or the CSW Operating Agreement. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
- Texas Wires revenues increased $17 million primarily due to favorable prices and a four percent increase in degree days.
- Transmission Revenues decreased $12 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT in 2005.
- Other revenues increased $23 million. This increase was due in part to $29 million of revenue from securitization transition charges primarily resulting from new financing in October 2006. This increase was partially offset by a $13 million decrease in third party construction project revenues related to work performed for the Lower Colorado River Authority. Securitization transition charges represent amounts collected to recover securitization bond principal and interest payments related to our securitized transition assets and are fully offset by amortization and interest expenses. See the "TCC Texas Restructuring" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $58 million primarily due to the sale of STP, which resulted in a decrease in generation-related operation and maintenance expenses of $29 million. An additional $12 million decrease resulted from lower expenses related to construction projects performed for third parties, primarily the Lower Colorado River Authority. The remaining decrease primarily related to lower administrative and general expenses, including outside services and regulatory expenses.
- Depreciation and Amortization expense increased $18 million primarily due to the amortization of the Securitization Bonds issued in October 2006 of $10 million and a $9 million increase related to the refund and amortization of excess earnings credits in 2005.
- Taxes Other Than Income Taxes decreased $9 million primarily due to lower property-related and other taxes as a result of the sale of STP in 2005 and a favorable settlement of a state use tax audit in 2006.
- Carrying Costs Income increased $88 million primarily due to negative adjustments of $29 million and $8 million made in the first and third quarters of 2005, respectively, related to our True-up Proceeding orders received from the PUCT. The remaining increase is due to the disallowance of carrying costs of $71 million in 2005 partially offset by lower amounts of carrying costs in 2006 (see "TCC Texas Restructuring" section of Note 4).
- Other Income decreased $7 million primarily due to interest income recorded in the prior year related to the 2005 Texas Court of Appeals order (see "Other Texas Restructuring Matters – Excess Earnings" section of Note 4).
- Interest Expense increased $32 million primarily due to a $22 million increase in accrued interest related to the CTC liability (see "TCC Texas Restructuring – TCC's 2006 CTC Proceeding" section of Note 4) and a $23 million increase in long-term debt interest primarily related to the affiliated note issuances and the Securitization Bonds issued in October 2006, partially offset by a $4 million decrease in interest expense related to Utility Money Pool borrowings and AFUDC.

Income Taxes

Income Tax Expense increased $10 million primarily due to the recording of tax reserve adjustments, a decrease in consolidated tax savings from Parent and an increase in state income taxes.

Financial Condition

Credit Ratings

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

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

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Interest on Fixed Rate Portion of Long-term Debt (a)	$ 129.0	$ 290.0	$ 260.0	$ 1,023.0	$ 1,702.0
Fixed Rate Portion of Long-term Debt (b)	78.0	281.0	307.0	2,191.0	2,857.0
Variable Rate Portion of Long-term Debt (c)	-	-	-	161.0	161.0
Capital Lease Obligations (d)	1.6	2.4	0.5	-	4.5
Noncancelable Operating Leases (d)	6.2	9.7	6.6	3.1	25.6
Construction Contracts for Assets (e)	82.1	-	-	-	82.1
Total	$ 296.9	$ 583.1	$ 574.1	$ 3,378.1	$ 4,832.2

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(b) See Note 15. Represents principal only excluding interest.
(c) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.60% and 3.75% at December 31, 2006.
(d) See Note 14.
(e) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2006 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 Years	Total
Guarantees of Our Performance (a)	$ 443	$ -	$ -	$ -	$ 443
Transmission Facilities for Third Parties (b)	21	12	-	-	33
Total	$ 464	$ 12	$ -	$ -	$ 476

(a) See "Contracts" section of Note 6.
(b) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

Texas Restructuring

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

TCC will recover its PUCT approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a credit competition transition charge (CTC) rate rider to refund its net regulatory liability for other true-up items.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units.

TCC appealed the PUCT true-up orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See "TCC and TNC Deferred Fuel" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections of Note 4.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. On February 1, 2007 the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT's April 4, 2006 final True-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC's stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC's nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC's future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC's nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge's other preliminary determinations that affirm the PUCT's decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management has concluded that it is probable that the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. TCC cannot estimate the amount at this time, but the amount could exceed its Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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

Our MTM Risk Management Contract Net Assets were zero as of December 31, 2006. For further explanation, see "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4. The following table summarizes the reasons for changes in our total MTM value as compared to December 31, 2005.

MTM Risk Management Contract Net Assets
Year Ended December 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		(1,615)
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		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(3,428)
Changes Due to SIA and CSW Operating Agreement (c)		(383)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		-
Total MTM Risk Management Contract Net Assets		-
Net Cash Flow Hedge Contracts		-
Total MTM Risk Management Contract Net Assets at December 31, 2006	$	-

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our MTM Risk Management Contract Net Assets were zero as of December 31, 2006. Therefore, there is no maturity and source of fair value to report.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on our future cash flows. 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (224)
Changes in Fair Value	-
Impact Due to Changes in SIA (a)	218
Reclassifications from AOCI to Net Loss for Cash Flow Hedges Settled	6
Ending Balance in AOCI December 31, 2006	$ -

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

Credit Risk

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

VaR Associated with Risk Management Contracts

Our MTM Risk Management Contract Net Assets were zero as of December 31, 2006. Therefore, the ending VaR at December 31, 2006 was zero.

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 $81 million and $93 million at December 31, 2006 and 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 SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 623,840	$ 729,815	$ 1,148,930
Sales to AEP Affiliates	6,403	14,973	47,039
Other	34,421	48,458	16,880
TOTAL	664,664	793,246	1,212,849
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	6,591	13,363	60,725
Fuel from Affiliates Used for Electric Generation	77	84	101,906
Purchased Electricity for Resale	4,093	28,947	206,304
Purchased Electricity from AEP Affiliates	-	-	6,140
Other Operation	240,795	286,708	307,939
Maintenance	38,466	50,888	63,599
Depreciation and Amortization	164,773	146,258	131,154
Taxes Other Than Income Taxes	80,772	89,717	91,001
TOTAL	535,567	615,965	968,768
OPERATING INCOME	129,097	177,281	244,081
Other Income (Expense):			
Interest Income	7,488	16,228	6,604
Carrying Costs Income (Expense)	69,080	(19,293)	301,644
Allowance for Equity Funds Used During Construction	2,688	1,003	1,170
Interest Expense	(144,134)	(112,006)	(123,785)
INCOME BEFORE INCOME TAXES	64,219	63,213	429,714
Income Tax Expense	22,650	12,441	135,058
INCOME BEFORE EXTRAORDINARY LOSS	41,569	50,772	294,656
EXTRAORDINARY LOSS ON STRANDED COST RECOVERY, NET OF TAX	-	(224,551)	(120,534)
NET INCOME (LOSS)	41,569	(173,779)	174,122
Preferred Stock Dividend Requirements	241	241	241
Gain on Reacquired Preferred Stock	6	-	-
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 41,334	$ (174,020)	$ 173,881

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

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 55,292	$ 132,606	$ 1,083,023	$ (61,872)	$ 1,209,049
Common Stock Dividends			(172,000)		(172,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,036,808
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,338				2,485	2,485
Minimum Pension Liability, Net of Tax of $31,790				55,228	55,228
NET INCOME			174,122		174,122
TOTAL COMPREHENSIVE INCOME					231,835
DECEMBER 31, 2004	55,292	132,606	1,084,904	(4,159)	1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,118,402
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $474				(881)	(881)
Minimum Pension Liability, Net of Tax of $42				3,888	3,888
NET LOSS			(173,779)		(173,779)
TOTAL COMPREHENSIVE LOSS					(170,772)
DECEMBER 31, 2005	55,292	132,606	760,884	(1,152)	947,630
Common Stock Dividends			(585,000)		(585,000)
Preferred Stock Dividends			(241)		(241)
Gain on Reacquired Preferred Stock			6		6
TOTAL					362,395
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $121				224	224
Minimum Pension Liability, Net of Tax of $108				200	200
NET INCOME			41,569		41,569
TOTAL COMPREHENSIVE INCOME					41,993
Minimum Pension Liability Elimination, Net of Tax of $392				728	728
DECEMBER 31, 2006	$ 55,292	$ 132,606	$ 217,218	$ -	$ 405,116

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 779	$ -
Other Cash Deposits	104,203	66,153
Advances to Affiliates	394,004	-
Accounts Receivable:		
Customers	31,215	209,957
Affiliated Companies	8,613	23,486
Accrued Unbilled Revenues	10,093	25,606
Allowance for Uncollectible Accounts	(49)	(143)
Total Accounts Receivable	49,872	258,906
Unbilled Construction Costs	4,535	19,440
Materials and Supplies	28,347	13,897
Risk Management Assets	-	14,311
Prepayments and Other	1,137	5,231
TOTAL	582,877	377,938
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	904,527	817,351
Distribution	1,579,498	1,476,683
Other	220,028	233,361
Construction Work in Progress	165,979	129,800
Total	2,870,032	2,657,195
Accumulated Depreciation and Amortization	630,239	636,078
TOTAL - NET	2,239,793	2,021,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	193,111	1,688,787
Securitized Transition Assets	2,158,408	593,401
Long-term Risk Management Assets	-	11,609
Employee Benefits and Pension Assets	35,574	114,733
Deferred Charges and Other	69,493	53,011
TOTAL	2,456,586	2,461,541
Assets Held for Sale – Texas Generation Plant	44,475	44,316
TOTAL ASSETS	$ 5,323,731	$ 4,904,912

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 82,080
Accounts Payable:		
General	26,934	82,666
Affiliated Companies	21,234	65,574
Long-term Debt Due Within One Year – Nonaffiliated	78,227	152,900
Risk Management Liabilities	-	13,024
Customer Deposits	18,742	10,658
Accrued Taxes	74,499	54,566
Accrued Interest	44,712	32,497
Other	34,762	35,269
TOTAL	299,110	529,234
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,937,387	1,550,596
Long-term Debt – Affiliated	-	150,000
Long-term Risk Management Liabilities	-	7,857
Deferred Income Taxes	1,034,123	1,048,372
Regulatory Liabilities and Deferred Investment Tax Credits	598,027	652,143
Deferred Credits and Other	44,047	13,140
TOTAL	4,613,584	3,422,108
TOTAL LIABILITIES	4,912,694	3,951,342
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,921	5,940
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $25 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	217,218	760,884
Accumulated Other Comprehensive Income (Loss)	-	(1,152)
TOTAL	405,116	947,630
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,323,731	$ 4,904,912

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income (Loss)	$ 41,569	$ (173,779)	$ 174,122
Adjustments for Noncash Items:			
Depreciation and Amortization	164,773	146,258	131,154
Deferred Income Taxes	24,200	(91,387)	16,490
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	-	224,551	120,534
Carrying Costs on Stranded Cost Recovery	(69,080)	19,293	(301,644)
Mark-to-Market of Risk Management Contracts	5,426	4,275	2,241
Wholesale Capacity Auction True-up	(826)	769	(79,973)
Pension Contributions to Qualified Plan Trusts	-	(3,953)	(61,910)
Fuel Over/Under Recovery, Net	(12,424)	(34,328)	61,500
Change in Other Noncurrent Assets	(15,263)	(12,644)	91,502
Change in Other Noncurrent Liabilities	(59,568)	3,609	(3,473)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	209,034	(28,947)	2,352
Fuel, Materials and Supplies	(15,303)	(1,559)	(10,641)
Accounts Payable	(105,537)	6,797	26,008
Accrued Taxes, Net	19,933	(128,022)	116,996
Other Current Assets	18,999	(14,313)	1,817
Other Current Liabilities	18,180	11,113	(467)
Net Cash Flows From (Used For) Operating Activities	224,113	(72,267)	286,608
INVESTING ACTIVITIES			
Construction Expenditures	(270,330)	(178,628)	(106,656)
Change in Other Cash Deposits, Net	(37,407)	68,953	(70,062)
Change in Advances to Affiliates, Net	(394,004)	-	60,699
Purchases of Investment Securities	-	(154,364)	(99,667)
Sales of Investment Securities	-	149,804	87,471
Proceeds from Sale of Assets	9,380	315,318	429,553
Other	-	-	(36,191)
Net Cash Flows From (Used For) Investing Activities	(692,361)	201,083	265,147
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	1,715,285	316,901	-
Issuance of Long-term Debt – Affiliated	195,000	150,000	-
Change in Advances from Affiliates, Net	(82,080)	81,873	207
Retirement of Long-term Debt – Nonaffiliated	(427,900)	(526,897)	(380,096)
Retirement of Long-term Debt – Affiliated	(345,000)	-	-
Retirement of Cumulative Preferred Stock	(13)	-	-
Principal Payments for Capital Lease Obligations	(1,024)	(478)	(436)
Dividends Paid on Common Stock	(585,000)	(150,000)	(172,000)
Dividends Paid on Cumulative Preferred Stock	(241)	(241)	(241)
Net Cash Flows From (Used For) Financing Activities	469,027	(128,842)	(552,566)
Net Increase (Decrease) in Cash and Cash Equivalents	779	(26)	(811)
Cash and Cash Equivalents at Beginning of Period	-	26	837
Cash and Cash Equivalents at End of Period	$ 779	$ -	$ 26
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 105,896	$ 104,701	$ 117,325
Net Cash Paid (Received) for Income Taxes	(24,649)	235,697	(1,058)
Noncash Acquisitions Under Capital Leases	3,572	977	348
Construction Expenditures Included in Accounts Payable at December 31,	16,502	11,037	1,838

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
AEP Texas Central Company:

We have audited the accompanying consolidated balance sheets of AEP Texas Central Company and subsidiaries (the “Company”) as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the consolidated financial statements, respectively, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006, and FASB Staff Position No. FAS 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003,” effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

AEP TEXAS NORTH COMPANY AND SUBSIDIARY

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 329,470	$ 458,888	$ 553,458	$ 533,511	$ 503,408
Operating Income (Loss)	$ 35,287	$ 76,699	$ 91,071	$ 107,405	$ (6,250)
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 14,943	$ 41,476	$ 47,659	$ 55,663	$ (13,677)
Extraordinary Loss, Net of Tax	-	-	-	(177)	-
Cumulative Effect of Accounting Changes, Net of Tax	-	(8,472)	-	3,071	-
Net Income (Loss)	$ 14,943	$ 33,004	$ 47,659	$ 58,557	$ (13,677)
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,328,893	$ 1,285,114	$ 1,305,571	$ 1,281,620	$ 1,249,996
Accumulated Depreciation and Amortization	486,961	478,519	527,770	507,420	493,981
Net Property, Plant and Equipment	$ 841,932	$ 806,595	$ 777,801	$ 774,200	$ 756,015
Total Assets	$ 967,514	$ 1,043,834	$ 1,043,162	$ 978,801	$ 965,916
Common Shareholder's Equity	$ 306,356	$ 313,919	$ 310,421	$ 238,275	$ 180,744
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 2,349	$ 2,357	$ 2,357	$ 2,357	$ 2,367
Long-term Debt (a)	$ 276,936	$ 276,845	$ 314,357	$ 356,754	$ 132,500
Obligations Under Capital Leases (a)	$ 1,643	$ 724	$ 534	$ 473	$ -

(a) Including portion due within one year.

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

As a public utility, we engage in the transmission and distribution of electric power to 189,000 retail customers through REPs in our service territory in western and central Texas. Although we engage in the generation and purchase of electric power for sale to the market and to meet wholesale contracts, the deregulation of electric power in the state of Texas requires this activity to be separated from our transmission and distribution activities. We also sell electric power at wholesale to other utilities, municipalities, rural electric cooperatives and REPs in Texas. We consolidate Texas North Generation Company, LLC, our wholly-owned subsidiary.

Under the Texas Restructuring Legislation, we completed the final stage of exiting the generation business and ceased serving retail load. Based on the corporate separation and generation divestiture, 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, we sought and received FERC approval to be removed from those agreements. Our sharing of margins under the CSW Operating Agreement ceased on May 1, 2006. The sharing of margins with AEP East companies under the SIA ceased on April 1, 2006. These trading and marketing margins affected our results of operations and cash flows.

Prior to May 1, 2006, as a member of the CSW Operating Agreement, we were compensated for energy delivered to other members based upon our incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies were generally shared among the members based upon the relative magnitude of the energy each member provided to make such sales.

Prior to April 1, 2006, under the SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities were shared among AEP East companies and AEP West companies. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$	41
Changes in Gross Margin:			
Off-system Sales	(35)		
Texas Wires	(3)		
Transmission Revenues	(4)		
Other	(39)		
Total Change in Gross Margin			(81)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	41		
Depreciation and Amortization	(1)		
Taxes Other Than Income Taxes	1		
Other Income	(2)		
Interest Expense	2		
Total Change in Operating Expenses and Other			41
Income Tax Expense			14
Year Ended December 31, 2006		$	15

Income Before Cumulative Effect of Accounting Change decreased $26 million primarily due to a decrease in Gross Margin of $81 million partially offset by a reduction in Other Operation and Maintenance expenses of $41 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:

- Margins from Off-system Sales decreased $35 million primarily due to a $28 million decrease in dedicated energy and capacity sales, which resulted from the market conditions within ERCOT. An additional $7 million decrease was primarily due to a decrease in our allocation of off-system sales margins under the SIA. As of May 1, 2006, we no longer share off-system sales margins under the SIA or the CSW Operating Agreement. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.
- Transmission Revenues decreased $4 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT in 2005.
- Other revenues decreased $39 million primarily resulting from the completion of third party construction projects 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 $41 million primarily resulting from the completion of third party construction projects related to work performed for the Lower Colorado River Authority.

Income Taxes

Income Tax Expense decreased $14 million 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 has us on a 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-

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Interest on Fixed Rate Portion of Long-term Debt (a)	$ 15.0	$ 30.0	$ 30.0	$ 41.0	$ 116.0
Fixed Rate Portion of Long-term Debt (b)	8.2	-	-	269.3	277.5
Capital Lease Obligations (c)	0.6	0.9	0.3	-	1.8
Noncancelable Operating Leases (c)	2.7	4.8	3.2	2.0	12.7
Construction Contracts for Capital Assets (d)	31.6	-	-	-	31.6
Total	$ 58.1	$ 35.7	$ 33.5	$ 312.3	$ 439.6

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(b) See Note 15. Represents principal only excluding interest.
(c) See Note 14.
(d) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

Oklaunion PPA between TNC and AEP Energy Partners

On January 1, 2007, we began a twenty-year Power Purchase and Sale Agreement (PPA) with an affiliate, AEP Energy Partners (AEPEP), whereby we will sell the output from its undivided interest (54.69%) in the Oklaunion plant to AEPEP. A portion of the payment is a fixed capacity payment that is required to be paid even if no power is taken by AEPEP.

We treat this arrangement as an operating lease. The payments that we expect to receive from AEPEP for 2007 are estimated to total $96 million, which include capacity, operations and maintenance, fuel, other taxes and depreciation.

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” 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 balance sheet as of December 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 Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ -	$ -	$ -
Noncurrent Assets	-	-	-
Total MTM Derivative Contract Assets	-	-	-
Current Liabilities	-	-	-
Noncurrent Liabilities	-	(1,081)	(1,081)
Total MTM Derivative Contract Liabilities	-	(1,081)	(1,081)
Total MTM Derivative Contract Net Assets (Liabilities)	$ -	$ (1,081)	$ (1,081)

MTM Risk Management Contract Net Assets
Year Ended December 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	(804)
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	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(1,080)
Changes Due to SIA and CSW Operating Agreement (c)	(814)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	-
Total MTM Risk Management Contract Net Assets	-
Net Cash Flow Hedge Contracts	(1,081)
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ (1,081)

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our MTM Risk Management Net Assets are zero as of December 31, 2006. Therefore, there is no maturity and source value to report.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (111)
Changes in Fair Value	(703)
Impact Due to Changes in SIA (a)	98
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	14
Ending Balance in AOCI December 31, 2006	$ (702)

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is zero.

Credit Risk

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

VaR Associated with Risk Management Contracts

Our MTM Risk Management Contract Net Assets are zero as of December 31, 2006. Therefore, the ending VaR at December 31, 2006 was zero.

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 $12 million and $13 million at December 31, 2006 and 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.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 295,930	$ 369,954	$ 447,908
Sales to AEP Affiliates	33,225	47,164	51,680
Other	315	41,770	53,870
TOTAL	329,470	458,888	553,458
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	46,173	46,953	54,447
Fuel from Affiliates Used for Electric Generation	537	629	46,496
Purchased Electricity for Resale	72,760	125,567	133,770
Purchased Electricity from AEP Affiliates	5,948	23	5,211
Other Operation	81,437	120,618	140,206
Maintenance	21,846	23,636	20,602
Depreciation and Amortization	42,914	41,466	39,025
Taxes Other Than Income Taxes	22,568	23,297	22,630
TOTAL	294,183	382,189	462,387
OPERATING INCOME	35,287	76,699	91,071
Other Income (Expense):			
Interest Income	643	2,447	665
Allowance for Equity Funds Used During Construction	886	724	417
Interest Expense	(17,619)	(19,817)	(21,985)
INCOME BEFORE INCOME TAXES	19,197	60,053	70,168
Income Tax Expense	4,254	18,577	22,509
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	14,943	41,476	47,659
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(8,472)	-
NET INCOME	14,943	33,004	47,659
Preferred Stock Dividend Requirements	103	104	103
Gain on Reacquired Preferred Stock	2	-	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 14,842	$ 32,900	$ 47,556

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

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

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 137,214	$ 2,351	$ 125,428	$ (26,718)	$ 238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					236,172
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $477				886	886
Minimum Pension Liability, Net of Tax of $13,841				25,704	25,704
NET INCOME			47,659		47,659
TOTAL COMPREHENSIVE INCOME					74,249
DECEMBER 31, 2004	137,214	2,351	170,984	(128)	310,421
Common Stock Dividends			(29,026)		(29,026)
Preferred Stock Dividends			(104)		(104)
TOTAL					281,291
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $213				(396)	(396)
Minimum Pension Liability, Net of Tax of $11				20	20
NET INCOME			33,004		33,004
TOTAL COMPREHENSIVE INCOME					32,628
DECEMBER 31, 2005	137,214	2,351	174,858	(504)	313,919
Common Stock Dividends			(12,750)		(12,750)
Preferred Stock Dividends			(103)		(103)
Gain on Reacquired Preferred Stock			2		2
TOTAL					301,068
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $318				(591)	(591)
Minimum Pension Liability, Net of Tax of $37				68	68
NET INCOME			14,943		14,943
TOTAL COMPREHENSIVE INCOME					14,420
Minimum Pension Liability Elimination, Net of Tax of $175				325	325
SFAS 158 Adoption, Net of Tax of $5,092				(9,457)	(9,457)
DECEMBER 31, 2006	$ 137,214	$ 2,351	$ 176,950	$ (10,159)	$ 306,356

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

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 84	$ -
Other Cash Deposits	8,863	1,432
Advances to Affiliates	13,543	34,286
Accounts Receivable:		
Customers	21,742	77,678
Affiliated Companies	5,634	26,149
Accrued Unbilled Revenues	2,292	5,016
Allowance for Uncollectible Accounts	(9)	(18)
Total Accounts Receivable	29,659	108,825
Fuel	8,559	2,636
Materials and Supplies	9,319	6,858
Risk Management Assets	-	7,114
Prepayments and Other	1,681	3,772
TOTAL	71,708	164,923
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	290,485	288,934
Transmission	327,845	289,029
Distribution	512,265	492,878
Other	159,451	167,849
Construction Work in Progress	38,847	46,424
Total	1,328,893	1,285,114
Accumulated Depreciation and Amortization	486,961	478,519
TOTAL - NET	841,932	806,595
OTHER NONCURRENT ASSETS		
Regulatory Assets	38,402	9,787
Long-term Risk Management Assets	-	5,772
Employee Benefits and Pension Assets	12,867	46,289
Deferred Charges and Other	2,605	10,468
TOTAL	53,874	72,316
TOTAL ASSETS	$ 967,514	$ 1,043,834

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

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	$ 4,448	$ 19,739
Affiliated Companies	43,993	84,923
Long-term Debt Due Within One Year – Nonaffiliated	8,151	-
Risk Management Liabilities	-	6,475
Accrued Taxes	21,782	21,212
Other	14,934	21,050
TOTAL	93,308	153,399
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	268,785	276,845
Long-term Risk Management Liabilities	1,081	3,906
Deferred Income Taxes	124,048	132,335
Regulatory Liabilities and Deferred Investment Tax Credits	139,429	139,732
Deferred Credits and Other	32,158	21,341
TOTAL	565,501	574,159
TOTAL LIABILITIES	658,809	727,558
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,357
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $25 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	176,950	174,858
Accumulated Other Comprehensive Income (Loss)	(10,159)	(504)
TOTAL	306,356	313,919
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 967,514	$ 1,043,834

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

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 14,943	$ 33,004	$ 47,659
Adjustments for Noncash Items:			
Depreciation and Amortization	42,914	41,466	39,025
Deferred Income Taxes	(227)	(4,578)	4,236
Cumulative Effect of Accounting Change, Net of Tax	-	8,472	-
Mark-to-Market of Risk Management Contracts	2,698	1,494	428
Pension Contributions to Qualified Plan Trusts	-	(1,409)	(21,172)
Fuel Over/Under Recovery, Net	2,915	996	10,100
Change in Other Noncurrent Assets	(7,136)	(3,003)	(9,264)
Change in Other Noncurrent Liabilities	(7,812)	(1,897)	12,444
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	79,166	(2,513)	(20,620)
Fuel, Materials and Supplies	(8,384)	1,927	8,374
Accounts Payable	(54,379)	35,659	8,238
Accrued Taxes, Net	570	(16,057)	14,392
Unbilled Construction Costs	37	20,744	(5,122)
Other Current Assets	2,053	(99)	764
Other Current Liabilities	(5,943)	5,138	90
Net Cash Flows From Operating Activities	61,415	119,344	89,572
INVESTING ACTIVITIES			
Construction Expenditures	(70,350)	(63,014)	(35,901)
Change in Other Cash Deposits, Net	1,203	876	555
Change In Advances to Affiliates, Net	20,743	17,218	(9,911)
Proceeds from Sale of Assets	330	1,033	510
Other	-	(8,469)	-
Net Cash Flows Used for Investing Activities	(48,074)	(52,356)	(44,747)
FINANCING ACTIVITIES			
Retirement of Long-term Debt - Nonaffiliated	-	(37,609)	(42,506)
Retirement of Cumulative Preferred Stock	(6)	-	-
Principal Payments for Capital Lease Obligations	(398)	(249)	(216)
Dividends Paid on Common Stock	(12,750)	(29,026)	(2,000)
Dividends Paid on Cumulative Preferred Stock	(103)	(104)	(103)
Net Cash Flows Used For Financing Activities	(13,257)	(66,988)	(44,825)
Net Increase in Cash and Cash Equivalents	84	-	-
Cash and Cash Equivalents at Beginning of Period	-	-	-
Cash and Cash Equivalents at End of Period	$ 84	$ -	$ -
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 15,457	$ 19,042	$ 20,860
Net Cash Paid for Income Taxes	5,834	41,306	6,905
Noncash Acquisitions Under Capital Leases	1,291	442	282
Construction Expenditures Included in Accounts Payable at December 31,	1,317	3,159	1,034

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
AEP Texas North Company:

We have audited the accompanying consolidated balance sheets of AEP Texas North Company and subsidiary (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas North Company and subsidiary as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006. As discussed in Note 17 to the consolidated financial statements, the Company adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 9 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 2,394,028	$ 2,176,273	$ 1,957,846	$ 1,950,867	$ 1,848,258
Operating Income	$ 365,643	$ 283,388	$ 328,561	$ 416,410	$ 430,189
Income Before Cumulative Effect of Accounting Changes	$ 181,449	$ 135,832	$ 153,115	$ 202,783	$ 205,492
Cumulative Effect of Accounting Changes, Net of Tax	-	(2,256)	-	77,257	-
Net Income	$ 181,449	$ 133,576	$ 153,115	$ 280,040	$ 205,492
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 8,000,278	$ 7,176,961	$ 6,563,207	$ 6,174,158	$ 5,929,348
Accumulated Depreciation and Amortization	2,476,290	2,524,855	2,456,417	2,334,013	2,343,507
Net Property, Plant and Equipment	$ 5,523,988	$ 4,652,106	$ 4,106,790	$ 3,840,145	$ 3,585,841
Total Assets	$ 7,016,316	$ 6,254,093	$ 5,239,918	$ 4,977,011	$ 4,722,442
Common Shareholder's Equity	$ 2,036,174	$ 1,803,701	$ 1,409,718	$ 1,336,987	$ 1,166,057
Long-term Debt (a)	$ 2,598,664	$ 2,151,378	$ 1,784,598	$ 1,864,081	$ 1,893,861
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 17,763	$ 17,784	$ 17,784	$ 17,784	$ 17,790
Cumulative Preferred Stock Subject to Mandatory Redemption	$ -	$ -	$ -	$ 5,360	$ 10,860
Obligations Under Capital Leases (a)	$ 11,859	$ 14,892	$ 19,878	$ 25,352	$ 33,589

(a) Including portion due within one year.

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 949,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. We consolidate Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such 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. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO and sharing mechanisms with customers for off-system sales margins in West Virginia and Virginia. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$	136
Changes in Gross Margin:			
Retail Margins	57		
Off-system Sales	51		
Transmission Revenues	(42)		
Other	11		
Total Change in Gross Margin			77
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	20		
Depreciation and Amortization	(15)		
Carrying Costs Income	11		
Other Income	10		
Interest Expense	(23)		
Total Change in Operating Expenses and Other			3
Income Tax Expense			(35)
Year Ended December 31, 2006		$	181

Income Before Cumulative Effect of Accounting Change increased $45 million to $181 million in 2006 primarily due to an increase in Gross Margin of $77 million, partially offset by an increase in Income Tax Expense of $35 million.

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 $57 million in comparison to 2005 primarily due to:
  - A $71 million increase in retail revenues primarily related to a new industrial customer transferred from an affiliate in 2006 and new rates implemented in relation to our Virginia general rate case subject to refund. See the "APCo Virginia Base Rate Case" section of Note 4.
  - A $27 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower MLR share and our increased capacity, partially from our purchase of the Ceredo Generating Station in 2005.
  - A $20 million increase in fuel recovery mainly caused by the reactivation of the West Virginia fuel clause in July 2006. See the "APCo West Virginia Rate Case" section of Note 4.

  These increases were partially offset by:
  - A $45 million decrease related to the Expanded Net Energy Cost (ENEC) mechanism with West Virginia retail customers primarily due to pass-through of off-system sales margins. The mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with our West Virginia rate case. See the "APCo West Virginia Rate Case" section of Note 4.
  - An $18 million decrease in retail sales primarily due to decreased demand in the residential class associated with unfavorable weather conditions. Heating degree days decreased approximately 19% and cooling degree days decreased approximately 12%.
- Margins from Off-system Sales increased $51 million primarily due to a $51 million increase in physical sales margins and a $26 million increase in our allocation of off-system sales margins under the SIA, offset by a $26 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

- Transmission Revenues decreased $42 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $11 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other revenue increased $11 million primarily due to the reversal of previously deferred gains on sales of allowances associated with the Virginia Environmental and Reliability Costs (E&R) case. See "APCo Virginia Environmental and Reliability Costs" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $20 million mainly due to a decrease in expenses associated with the Transmission Equalization Agreement with the addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
- Depreciation and Amortization expenses increased $15 million primarily due to the disallowance of certain depreciation expenses previously capitalized in our E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 4.
- Carrying Costs Income increased $11 million related to carrying costs associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 4.
- Other Income increased $10 million primarily due to interest income related to an increase in Advances to Affiliates during the year and an increase in AFUDC related to our environmental investment program.
- Interest Expense increased $23 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense increased $35 million primarily due to an increase in pretax book income and state income taxes.

<u>2005 Compared to 2004</u>

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 153
Changes in Gross Margin:		
Retail Margins	(55)	
Off-system Sales	60	
Transmission Revenues	(15)	
Other	2	
Total Change in Gross Margin		(8)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(40)	
Depreciation and Amortization	3	
Carrying Costs Income	14	
Other Income	2	
Interest Expense	(7)	
Total Change in Operating Expenses and Other		(28)
Income Tax Expense		19
Year Ended December 31, 2005		$ 136

Income Before Cumulative Effect of Accounting Change decreased $17 million to $136 million in 2005. The key drivers of the decrease were a $28 million net increase in operating expenses and other and an $8 million net decrease in Gross Margin offset by a $19 million decrease 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 decreased $55 million in comparison to 2004 primarily due to:
  - A $57 million increase in capacity settlement payments to affiliates under the Interconnection Agreement due to our higher MLR share caused by our new peak demand that was established in December 2004.
  - A $27 million decrease in fuel margins resulting from higher delivered fuel costs.

  The decreases were partially offset by:
  - A $26 million increase in retail sales due to favorable weather conditions. Cooling degree days increased approximately 11%.
- Off-system Sales for 2005 increased $60 million compared to 2004 primarily due to increased AEP Power Pool physical sales as well as favorable optimization activities.
- Transmission Revenues decreased $15 million primarily due to the elimination of revenues related to through and out rates partially offset by revenues from replacement SECA rates. See "Transmission Rate Proceedings at The FERC" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $40 million primarily due to a $15 million increase in generation operation and maintenance expenses, a $10 million increase in system dispatch costs related to our operation in PJM and a $9 million increase in costs associated with the AEP Transmission Equalization Agreement.
- Carrying Costs Income increased $14 million primarily related to the establishment of a regulatory asset for carrying costs associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 4.
- Interest Expense increased $7 million primarily due to long-term debt issuances in 2005.

Income Taxes

Income Tax Expense decreased $19 million primarily due to a decrease in pretax book income and a reduction of 2005 state income taxes due in part to the phase-out of the Ohio Franchise Tax.

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 2006, 2005 and 2004 were as follows:

	2006	2005	2004
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,741	$ 1,543	$ 4,714
Cash Flows From (Used For):			
Operating Activities	468,275	151,474	406,324
Investing Activities	(880,397)	(687,515)	(391,904)
Financing Activities	412,699	536,239	(17,591)
Net Increase (Decrease) in Cash and Cash Equivalents	577	198	(3,171)
Cash and Cash Equivalents at End of Period	$ 2,318	$ 1,741	$ 1,543

Operating Activities

Net Cash Flows From Operating Activities were $468 million in 2006. We produced income of $181 million during the period and noncash expense items of $206 million for Depreciation and Amortization and $17 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items in 2006.

Net Cash Flows From Operating Activities were $151 million in 2005. We produced income of $134 million during the period and noncash expense items of $191 million for Depreciation and Amortization and $73 million for Deferred Income Taxes offset by an increase in Pension Contributions to Qualified Plan Trusts of $129 million. 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 one significant item, a decrease in Accrued Taxes, Net of $74 million. During 2005, we made federal income tax payments of $75 million.

Net Cash Flows From Operating Activities were $406 million in 2004. We produced income of $153 million during the period and noncash expense items of $194 million for Depreciation and Amortization and $48 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item, an increase in Accrued Taxes, Net of $40 million. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. A payment was made in March 2005 when the 2004 federal income tax return extension was filed.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006, 2005, and 2004 primarily reflect our construction expenditures of $893 million, $598 million, and $437 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2006, 2005 and 2004, capital projects for transmission expenditures are primarily related to the Wyoming-Jacksons Ferry 765 KV line placed into service in June 2006. Environmental upgrades include the installation of selective catalytic reduction equipment on our plants and the flue gas desulfurization project at the Amos and Mountaineer plants. In 2005, we also acquired the Ceredo Generating Station for approximately $100 million.

Financing Activities

Net Cash Flows From Financing Activities were $413 million in 2006. We issued $500 million in Senior Unsecured Notes and $50 million in Pollution Control Bonds. We also received Capital Contributions from Parent Company of $100 million and retired $100 million of First Mortgage Bonds. We reduced short-term borrowings from the Utility Money Pool by $159 million. In addition, we received funds of $68 million related to a long-term coal purchase contract amended in March 2006, partially offset by repayments of $24 million. See “Coal Contract Amendment” within “Significant Factors” for additional information.

Net Cash Flows From Financing Activities were $536 million in 2005. We issued Senior Unsecured Notes of $850 million and Notes Payable - Affiliated of $100 million. We also received Capital Contributions from Parent Company of $200 million. We retired $450 million of Senior Unsecured Notes and three series of First Mortgage Bonds totaling $125 million. We reduced short-term borrowings from the Utility Money Pool by $17 million.

Net Cash Flows Used For Financing Activities were $18 million in 2004. We issued Senior Unsecured Notes of $125 million and reacquired First Mortgage Bonds, Senior Unsecured Notes, and Installment Purchase Contracts of $116 million, $50 million, and $40 million, respectively, at higher stated interest rates. We also increased borrowings from the Utility Money Pool of $128 million and paid common dividends of $50 million.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 35.0	$ -	$ -	$ -	$ 35.0
Interest on Fixed Rate Portion of Long-term Debt (b)	124.0	216.0	174.0	1,196.0	1,710.0
Fixed Rate Portion of Long-term Debt (c)	200.0	350.0	500.0	1,301.0	2,351.0
Variable Rate Portion of Long-term Debt (d)	124.0	-	-	139.0	263.0
Capital Lease Obligations (e)	4.8	6.3	1.8	0.3	13.2
Noncancelable Operating Leases (e)	12.4	19.9	13.5	14.7	60.5
Fuel Purchase Contracts (f)	627.2	873.6	548.8	1,847.8	3,897.4
Energy and Capacity Purchase Contracts (g)	3.2	4.8	7.1	1.5	16.6
Construction Contracts for Capital Assets (h)	323.8	252.0	-	323.1	898.9
Total	$ 1,454.4	$ 1,722.6	$ 1,245.2	$ 4,823.4	$ 9,245.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.50% and 5.69% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

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 Consolidated Balance Sheet and recorded the remaining $7 million as a reduction to Fuel and Other Consumables for Electric Generation on our Consolidated Statement of Income. We recorded the $68 million payment within Deferred Credits and Other on our 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 of which $24 million occurred in 2006 and $44 million is expected to occur in 2007. The remaining $44 million is recorded in Current Liabilities – Other on our Consolidated Balance Sheet at December 31, 2006.

New Generation

In January 2006, we filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to our existing Mountaineer generating station in Mason County, West Virginia. In January 2007, the WVPSC issued an order granting our motion to delay the Commission's statutory deadline for issuing an order on the certificate for the construction of the proposed IGCC plant. The WVPSC approved a deadline of December 3, 2007. Through December 31, 2006, we deferred pre-construction IGCC costs totaling $10 million.

Virginia Restructuring

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, cash flows and financial condition.

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

<u>Critical Accounting Estimates</u>

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 on our balance sheet as of December 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 Consolidated Balance Sheet As of December 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 96,437	$ 8,939	$ -	$ 105,376
Noncurrent Assets	88,780	126	-	88,906
Total MTM Derivative Contract Assets	185,217	9,065	-	194,282
Current Liabilities	(77,028)	(1,696)	(2,390)	(81,114)
Noncurrent Liabilities	(55,700)	(375)	(8,834)	(64,909)
Total MTM Derivative Contract Liabilities	(132,728)	(2,071)	(11,224)	(146,023)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 52,489	$ 6,994	$ (11,224)	$ 48,259

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 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		(9,668)
Fair Value of New Contracts at Inception When Entered During the Period (a)		499
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(279)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		316
Changes in Fair Value Due to Market Fluctuations During the Period (b)		5,007
Changes Due to SIA Agreement (c)		(6,533)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		6,740
Total MTM Risk Management Contract Net Assets		52,489
Net Cash Flow & Fair Value Hedge Contracts		6,994
DETM Assignment (e)		(11,224)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$	48,259

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 5,379	$ 3,847	$ 645	$ -	$ -	$ -	$ 9,871
Prices Provided by Other External Sources – OTC Broker Quotes (a)	15,738	5,180	7,521	-	-	-	28,439
Prices Based on Models and Other Valuation Methods (b)	(1,708)	781	3,860	8,631	1,137	1,478	14,179
Total	$ 19,409	$ 9,808	$ 12,026	$ 8,631	$ 1,137	$ 1,478	$ 52,489

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

We use interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock-in prices on certain transactions 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 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	5,414	-	4,951	10,365
Impact due to Changes in SIA (a)	(442)	-	-	(442)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	1,840	7	2,104	3,951
Ending Balance in AOCI December 31, 2006	$ 5,332	$ (164)	$ (7,715)	$ (2,547)

(a) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,709 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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$756	$1,915	$658	$358	$732	$1,216	$579	$209

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

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 $153 million and $142 million at December 31, 2006 and 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
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,145,639	$ 1,845,170	$ 1,698,220
Sales to AEP Affiliates	238,592	322,333	252,128
Other	9,797	8,770	7,498
TOTAL	2,394,028	2,176,273	1,957,846
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	638,862	549,773	432,420
Purchased Electricity for Resale	123,592	110,693	84,433
Purchased Electricity from AEP Affiliates	492,756	453,600	370,953
Other Operation	284,350	315,605	279,075
Maintenance	190,697	179,119	175,283
Depreciation and Amortization	205,666	191,128	194,356
Taxes Other Than Income Taxes	92,462	92,967	92,765
TOTAL	2,028,385	1,892,885	1,629,285
OPERATING INCOME	365,643	283,388	328,561
Other Income (Expense):			
Interest Income	8,648	2,540	1,985
Carrying Costs Income	25,666	14,438	255
Allowance for Equity Funds Used During Construction	12,014	7,956	6,560
Interest Expense	(129,106)	(106,301)	(99,135)
INCOME BEFORE INCOME TAXES	282,865	202,021	238,226
Income Tax Expense	101,416	66,189	85,111
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	181,449	135,832	153,115
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(2,256)	-
NET INCOME	181,449	133,576	153,115
Preferred Stock Dividend Requirements including Capital Stock Expense and Other	952	2,178	3,215
EARNINGS APPLICABLE TO COMMON STOCK	$ 180,497	$ 131,398	$ 149,900

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

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 260,458	$ 719,899	$ 408,718	$ (52,088)	$ 1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense		2,415	(2,415)		-
TOTAL					1,286,187
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,176				(7,755)	(7,755)
Minimum Pension Liability, Net of Tax of $11,754				(21,829)	(21,829)
NET INCOME			153,115		153,115
TOTAL COMPREHENSIVE INCOME					123,531
DECEMBER 31, 2004	260,458	722,314	508,618	(81,672)	1,409,718
Capital Contributions From Parent		200,000			200,000
Common Stock Dividends			(5,000)		(5,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense and Other		2,523	(1,378)		1,145
TOTAL					1,605,063
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,821				(7,097)	(7,097)
Minimum Pension Liability, Net of Tax of $38,855				72,159	72,159
NET INCOME			133,576		133,576
TOTAL COMPREHENSIVE INCOME					198,638
DECEMBER 31, 2005	260,458	924,837	635,016	(16,610)	1,803,701
Capital Contributions From Parent		100,000			100,000
Common Stock Dividends			(10,000)		(10,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense and Other		157	(152)		5
TOTAL					1,892,906
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,471				13,874	13,874
Minimum Pension Liability, Net of Tax of $7				(14)	(14)
NET INCOME			181,449		181,449
TOTAL COMPREHENSIVE INCOME					195,309
Minimum Pension Liability Elimination, Net of Tax of $109				203	203
SFAS 158 Adoption, Net of Tax of $28,132				(52,244)	(52,244)
DECEMBER 31, 2006	$ 260,458	$ 1,024,994	$ 805,513	$ (54,791)	$ 2,036,174

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

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

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,318	$ 1,741
Accounts Receivable:		
Customers	180,190	141,810
Affiliated Companies	98,237	153,453
Accrued Unbilled Revenues	46,281	51,201
Miscellaneous	3,400	527
Allowance for Uncollectible Accounts	(4,334)	(1,805)
Total Accounts Receivable	323,774	345,186
Fuel	77,077	64,657
Materials and Supplies	56,235	54,967
Risk Management Assets	105,376	132,247
Accrued Tax Benefits	3,748	32,979
Regulatory Asset for Under-Recovered Fuel Costs	29,526	30,697
Prepayments and Other	20,126	44,432
TOTAL	618,180	706,906
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,844,803	2,798,157
Transmission	1,620,512	1,266,855
Distribution	2,237,887	2,141,153
Other	339,450	323,158
Construction Work in Progress	957,626	647,638
Total	8,000,278	7,176,961
Accumulated Depreciation and Amortization	2,476,290	2,524,855
TOTAL - NET	5,523,988	4,652,106
OTHER NONCURRENT ASSETS		
Regulatory Assets	622,153	457,294
Long-term Risk Management Assets	88,906	176,231
Deferred Charges and Other	163,089	261,556
TOTAL	874,148	895,081
TOTAL ASSETS	$ 7,016,316	$ 6,254,093

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 34,975	$ 194,133
Accounts Payable:		
General	296,437	230,570
Affiliated Companies	105,525	85,941
Long-term Debt Due Within One Year – Nonaffiliated	324,191	146,999
Risk Management Liabilities	81,114	121,165
Customer Deposits	56,364	79,854
Accrued Taxes	60,056	49,833
Other	172,943	108,746
TOTAL	1,131,605	1,017,241
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,174,473	1,904,379
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	64,909	147,117
Deferred Income Taxes	957,229	952,497
Regulatory Liabilities and Deferred Investment Tax Credits	309,724	201,230
Deferred Credits and Other	224,439	110,144
TOTAL	3,830,774	3,415,367
TOTAL LIABILITIES	4,962,379	4,432,608
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,763	17,784
Commitments and Contingencies (Note 6)		
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	1,024,994	924,837
Retained Earnings	805,513	635,016
Accumulated Other Comprehensive Income (Loss)	(54,791)	(16,610)
TOTAL	2,036,174	1,803,701
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,016,316	$ 6,254,093

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

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 181,449	$ 133,576	$ 153,115
Adjustments for Noncash Items:			
Depreciation and Amortization	205,666	191,128	194,356
Deferred Income Taxes	17,225	72,763	47,585
Cumulative Effect of Accounting Change, Net of Tax	-	2,256	-
Carrying Costs Income	(25,666)	(14,438)	(255)
Mark-to-Market of Risk Management Contracts	2,824	(13,701)	5,391
Pension Contributions to Qualified Plan Trusts	-	(129,117)	(1,429)
Fuel Over/Under Recovery, Net	11,532	(36,499)	(10,861)
Change in Other Noncurrent Assets	(67,865)	(15,009)	(24,059)
Change in Other Noncurrent Liabilities	54,745	(13,741)	36,022
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	21,412	(26,665)	(6,608)
Fuel, Materials and Supplies	(13,688)	(25,419)	(2,795)
Accounts Payable	37,533	61,086	(21,696)
Customer Deposits	(23,490)	37,032	8,892
Accrued Taxes, Net	39,454	(73,550)	40,145
Other Current Assets	25,252	(24,831)	(3,237)
Other Current Liabilities	1,892	26,603	(8,242)
Net Cash Flows From Operating Activities	468,275	151,474	406,324
INVESTING ACTIVITIES			
Construction Expenditures	(892,816)	(597,808)	(436,535)
Change in Other Cash Deposits, Net	(945)	(24)	41,040
Purchase of Ceredo Generating Station	-	(100,000)	-
Proceeds from Sales of Assets	13,364	10,317	3,591
Net Cash Flows Used For Investing Activities	(880,397)	(687,515)	(391,904)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	100,000	200,000	-
Issuance of Long-term Debt – Nonaffiliated	561,710	840,469	124,398
Issuance of Long-term Debt – Affiliated	-	100,000	-
Change in Advances from Affiliates, Net	(159,158)	(16,927)	128,066
Retirement of Long-term Debt – Nonaffiliated	(117,511)	(575,010)	(206,008)
Retirement of Cumulative Preferred Stock	(16)	-	(5,360)
Principal Payments for Capital Lease Obligations	(5,166)	(6,493)	(7,887)
Funds From Amended Coal Contract	68,078	-	-
Amortization of Funds From Amended Coal Contract	(24,438)	-	-
Dividends Paid on Common Stock	(10,000)	(5,000)	(50,000)
Dividends Paid on Cumulative Preferred Stock	(800)	(800)	(800)
Net Cash Flows From (Used For) Financing Activities	412,699	536,239	(17,591)
Net Increase (Decrease) in Cash and Cash Equivalents	577	198	(3,171)
Cash and Cash Equivalents at Beginning of Period	1,741	1,543	4,714
Cash and Cash Equivalents at End of Period	$ 2,318	$ 1,741	$ 1,543
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 118,220	$ 91,373	$ 92,773
Net Cash Paid (Received) for Income Taxes	50,830	75,160	(831)
Noncash Acquisitions Under Capital Leases	3,017	1,988	3,791
Construction Expenditures Included in Accounts Payable at December 31,	130,558	82,640	37,356

In connection with the acquisition of Ceredo Generating Station in December 2005, we assumed $556 thousand of liabilities.

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the consolidated financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus,Ohio
February 28, 2007

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,806,735	$ 1,542,332	$ 1,447,925	$ 1,420,549	$ 1,424,583
Operating Income	$ 337,650	$ 242,880	$ 258,579	$ 295,412	$ 344,178
Income Before Cumulative Effect of Accounting Changes	$ 185,579	$ 137,799	$ 140,258	$ 173,147	$ 181,173
Cumulative Effect of Accounting Changes, Net of Tax	-	(839)	-	27,283	-
Net Income	$ 185,579	$ 136,960	$ 140,258	$ 200,430	$ 181,173
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 4,336,191	$ 4,026,653	$ 3,717,075	$ 3,598,388	$ 3,497,187
Accumulated Depreciation and Amortization	1,611,043	1,500,858	1,475,457	1,395,113	1,375,035
Net Property, Plant and Equipment	$ 2,725,148	$ 2,525,795	$ 2,241,618	$ 2,203,275	$ 2,122,152
Total Assets	$ 3,520,689	$ 3,432,794	$ 3,029,896	$ 2,838,366	$ 2,849,261
Common Shareholder's Equity	$ 1,056,017	$ 981,546	$ 898,650	$ 897,881	$ 847,664
Long-term Debt (a)	$ 1,197,322	$ 1,196,920	$ 987,626	$ 897,564	$ 621,626
Obligations Under Capital Leases (a)	$ 8,472	$ 9,576	$ 12,514	$ 15,618	$ 27,610

(a) Including portion due within one year.

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

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 742,000 retail customers in central and southern Ohio. We consolidate Colomet, Inc., Conesville Coal Preparation Company and Simco, Inc., our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such 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. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

<u>Results of Operations</u>

<u>2006 Compared to 2005</u>

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$ 138
Changes in Gross Margin:		
Retail Margins	113	
Off-system Sales	44	
Transmission Revenues	(21)	
Other	9	
Total Change in Gross Margin		145
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(32)	
Asset Impairments and Other Related Charges	39	
Depreciation and Amortization	(51)	
Taxes Other Than Income Taxes	(6)	
Carrying Costs Income	(6)	
Other Income	5	
Interest Expense	(7)	
Total Change in Operating Expenses and Other		(58)
Income Tax Expense		(39)
Year Ended December 31, 2006		$ 186

Income Before Cumulative Effect of Accounting Change increased $48 million to $186 million in 2006. The key drivers of the increase were a $145 million increase in Gross Margin and a $39 million asset impairment of Units 1 and 2 at our Conesville Plant in 2005, partially offset by a $51 million increase in Depreciation and Amortization expense, a $39 million increase in Income Tax Expense and a $32 million increase in Other Operation and Maintenance expenses.

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 $113 million primarily due to the RSP and Transition Regulatory Asset rate increases effective January 1, 2006, lower capacity settlement costs, and the addition of Monongahela Power's Ohio customers on December 31, 2005, partially offset by an increase in delivered fuel costs.
- Margins from Off-system Sales increased $44 million due to a $39 million increase in physical sales margins and a $14 million increase in our allocation of off-system sales margins under the SIA, partially offset by a $10 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
- Transmission Revenues decreased $21 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $6 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other revenues increased $9 million primarily due to increased gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $32 million primarily due to a $12 million increase in transmission expenses related to the AEP Transmission Equalization Agreement, a $6 million increase related to factored receivables, a $4 million increase in removal costs at the Conesville and Stuart plants, and a $4 million increase in boiler plant maintenance costs at the Conesville, Waterford and Zimmer Plants. The increase in expenses related to the factoring of accounts receivable is primarily due to an increase in accounts receivable factored, an increase in bad debt write-offs and an increase in short-term interest rates.
- Asset Impairments and Other Related Charges in the amount of $39 million were recorded last year due to the 2005 retirement of Units 1 and 2 at our Conesville Plant.
- Depreciation and Amortization expense increased $51 million primarily due to a $42 million increase in the amortization of regulatory assets and a larger depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power's Ohio assets. In addition, the 2005 RSP order resulted in a reversal of unused shopping credits of $18 million offset by the establishment of a $7 million regulatory liability to benefit low-income customers and economic development.
- Taxes Other Than Income Taxes increased $6 million due to increases in state excise taxes and property taxes associated with the Waterford and Monongahela asset additions, partially offset by accrual adjustments to property taxes that were favorable in 2006 and unfavorable in 2005.
- Carrying Costs Income decreased $6 million primarily due to the completion of deferrals of carrying costs on environmental capital expenditures from 2004 and 2005 that we continue to recover through 2008 in accordance with the RSP.
- Other Income increased $5 million due to interest income on tax refunds received for the years 1991 through 1996.
- Interest Expense increased $7 million primarily due to a new long-term debt issuance during the fourth quarter of 2005.

Income Taxes

Income Tax Expense increased $39 million primarily due to an increase in pretax book income and the recording of the tax reserve adjustments.

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-

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 0.7	$ -	$ -	$ -	$ 0.7
Interest on Fixed Rate Portion of Long-term Debt (b)	63.0	117.0	99.0	726.0	1,005.0
Fixed Rate Portion of Long-term Debt (c)	-	112.0	250.0	750.0	1,112.0
Variable Rate Portion of Long-term Debt (d)	-	-	-	92.0	92.0
Capital Lease Obligations (e)	3.2	4.7	1.4	0.1	9.4
Noncancelable Operating Leases (e)	5.3	8.8	5.7	4.5	24.3
Fuel Purchase Contracts (f)	163.3	317.5	286.1	340.4	1,107.3
Energy and Capacity Purchase Contracts (g)	35.8	3.0	4.5	1.0	44.3
Construction Contracts Assets (h)	161.0	50.0	-	4.6	215.6
Total	$ 432.3	$ 613.0	$ 646.7	$ 1,918.6	$ 3,610.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.53% and 3.75% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have 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.

Plant Acquisition – Darby Electric Generating Station

In November 2006, we agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW. This new generation acquisition will be financed by internally generated funds and short-term borrowings.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 balance sheet as of December 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
Consolidated Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 60,541	$ 5,697	$ -	$ 66,238
Noncurrent Assets	56,126	80	-	56,206
Total MTM Derivative Contract Assets	116,667	5,777	-	122,444
Current Liabilities	(47,204)	(557)	(1,524)	(49,285)
Noncurrent Liabilities	(34,830)	(17)	(5,630)	(40,477)
Total MTM Derivative Contract Liabilities	(82,034)	(574)	(7,154)	(89,762)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 34,633	$ 5,203	$ (7,154)	$ 32,682

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 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		(8,256)
Fair Value of New Contracts at Inception When Entered During the Period (a)		599
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(132)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		380
Changes in Fair Value Due to Market Fluctuations During the Period (b)		12,290
Changes Due to SIA Agreement (c)		(3,864)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		294
Total MTM Risk Management Contract Net Assets		34,633
Net Cash Flow Hedge Contracts		5,203
DETM Assignment (e)		(7,154)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$	32,682

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 3,316	$ 2,383	$ 411	$ -	$ -	$ -	$ 6,110
Prices Provided by Other External Sources – OTC Broker Quotes (a)	10,446	3,309	4,794	-	-	-	18,549
Prices Based on Models and Other Valuation Methods (b)	(425)	772	2,460	5,500	725	942	9,974
Total	$ 13,337	$ 6,464	$ 7,665	$ 5,500	$ 725	$ 942	$ 34,633

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(859)
Changes in Fair Value		3,438
Impact due to Changes in SIA (a)		(261)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		1,080
Ending Balance in AOCI December 31, 2006	$	3,398

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,357 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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$482	$1,224	$404	$228	$424	$705	$335	$121

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

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 $70 million and $86 million at December 31, 2006 and 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
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,715,542	$ 1,413,056	$ 1,340,152
Sales to AEP Affiliates	85,726	124,410	104,747
Other	5,467	4,866	3,026
TOTAL	1,806,735	1,542,332	1,447,925
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	294,841	255,913	211,314
Fuel from Affiliates Used for Electric Generation	-	-	10,603
Purchased Electricity for Resale	115,420	37,012	25,322
Purchased Electricity from AEP Affiliates	365,510	362,959	347,002
Other Operation	256,479	225,896	217,381
Maintenance	88,654	87,303	95,036
Asset Impairments and Other Related Charges	-	39,109	-
Depreciation and Amortization	193,251	142,346	148,529
Taxes Other Than Income Taxes	154,930	148,914	134,159
TOTAL	1,469,085	1,299,452	1,189,346
OPERATING INCOME	337,650	242,880	258,579
Other Income (Expense):			
Interest Income	8,885	3,972	1,993
Carrying Costs Income	4,122	10,367	486
Allowance for Equity Funds Used During Construction	1,865	1,579	1,117
Interest Expense	(66,100)	(59,539)	(54,246)
INCOME BEFORE INCOME TAXES	286,422	199,259	207,929
Income Tax Expense	100,843	61,460	67,671
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	185,579	137,799	140,258
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(839)	-
NET INCOME	185,579	136,960	140,258
Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense	157	2,620	1,015
EARNINGS APPLICABLE TO COMMON STOCK	$ 185,422	$ 134,340	$ 139,243

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

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 41,026	$ 576,400	$ 326,782	$ (46,327)	$ 897,881
Common Stock Dividends			(125,000)		(125,000)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					772,881
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $641				1,191	1,191
Minimum Pension Liability, Net of Tax of $8,443				(15,680)	(15,680)
NET INCOME			140,258		140,258
TOTAL COMPREHENSIVE INCOME					125,769
DECEMBER 31, 2004	41,026	577,415	341,025	(60,816)	898,650
Common Stock Dividends			(114,000)		(114,000)
Capital Stock Expense and Other		2,620	(2,620)		-
TOTAL					784,650
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,212				(2,252)	(2,252)
Minimum Pension Liability, Net of Tax of $33,486				62,188	62,188
NET INCOME			136,960		136,960
TOTAL COMPREHENSIVE INCOME					196,896
DECEMBER 31, 2005	41,026	580,035	361,365	(880)	981,546
Common Stock Dividends			(90,000)		(90,000)
Capital Stock Expense and Other		157	(157)		-
TOTAL					891,546
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,292				4,257	4,257
Minimum Pension Liability, Net of Tax of $2				(4)	(4)
NET INCOME			185,579		185,579
TOTAL COMPREHENSIVE INCOME					189,832
Minimum Pension Liability Elimination, Net of Tax of $14				25	25
SFAS 158 Adoption, Net of Tax of $13,670				(25,386)	(25,386)
DECEMBER 31, 2006	$ 41,026	$ 580,192	$ 456,787	$ (21,988)	$ 1,056,017

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

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

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,319	$ 940
Accounts Receivable:		
Customers	49,362	43,143
Affiliated Companies	62,866	67,694
Accrued Unbilled Revenues	11,042	10,086
Miscellaneous	4,895	2,012
Allowance for Uncollectible Accounts	(546)	(1,082)
Total Accounts Receivable	127,619	121,853
Fuel	37,348	28,579
Materials and Supplies	31,765	27,519
Emission Allowances	3,493	20,181
Risk Management Assets	66,238	76,507
Accrued Tax Benefits	4,763	36,838
Margin Deposits	7,747	16,832
Prepayments and Other	8,360	6,714
TOTAL	288,652	335,963
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,896,073	1,874,652
Transmission	479,119	457,937
Distribution	1,475,758	1,380,722
Other	191,103	184,096
Construction Work in Progress	294,138	129,246
Total	4,336,191	4,026,653
Accumulated Depreciation and Amortization	1,611,043	1,500,858
TOTAL - NET	2,725,148	2,525,795
OTHER NONCURRENT ASSETS		
Regulatory Assets	298,304	231,599
Long-term Risk Management Assets	56,206	101,512
Deferred Charges and Other	152,379	237,925
TOTAL	506,889	571,036
TOTAL ASSETS	$ 3,520,689	$ 3,432,794

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

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

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 696	$ 17,609
Accounts Payable:		
General	112,431	59,134
Affiliated Companies	59,538	59,399
Risk Management Liabilities	49,285	69,036
Customer Deposits	34,991	47,013
Accrued Taxes	166,551	157,729
Accrued Interest	20,868	18,908
Other	37,143	31,321
TOTAL	481,503	460,149
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,097,322	1,096,920
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	40,477	84,291
Deferred Income Taxes	475,888	498,232
Regulatory Liabilities and Deferred Investment Tax Credits	179,048	165,344
Deferred Credits and Other	90,434	46,312
TOTAL	1,983,169	1,991,099
TOTAL LIABILITIES	2,464,672	2,451,248
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,192	580,035
Retained Earnings	456,787	361,365
Accumulated Other Comprehensive Income (Loss)	(21,988)	(880)
TOTAL	1,056,017	981,546
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,520,689	$ 3,432,794

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

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 185,579	$ 136,960	$ 140,258
Adjustments for Noncash Items:			
Depreciation and Amortization	193,251	142,346	148,529
Deferred Income Taxes	(10,900)	19,209	13,395
Cumulative Effect of Accounting Change, Net of Tax	-	839	-
Asset Impairments and Other Related Charges	-	39,109	-
Carrying Costs Income	(4,122)	(10,367)	(486)
Mark-to-Market of Risk Management Contracts	(1,299)	(8,915)	2,887
Pension Contributions to Qualified Plan Trusts	-	(85,871)	(32)
Change in Other Noncurrent Assets	(33,812)	(26,711)	(23,837)
Change in Other Noncurrent Liabilities	16,013	9,979	3,904
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(5,766)	12,182	9,681
Fuel, Materials and Supplies	(13,015)	2,030	(20,636)
Accounts Payable	29,063	3,075	(1,604)
Customer Deposits	(12,022)	22,123	5,163
Accrued Taxes, Net	40,897	(78,278)	62,431
Other Current Assets	25,592	(12,001)	(7,802)
Other Current Liabilities	6,738	5,525	(1,864)
Net Cash Flows From Operating Activities	416,197	171,234	329,987
INVESTING ACTIVITIES			
Construction Expenditures	(306,559)	(165,452)	(147,102)
Change in Other Cash Deposits, Net	(1,151)	-	-
Change in Advances to Affiliates, Net	-	141,550	(141,550)
Purchase of Waterford Plant	-	(218,357)	-
Purchase of Monongahela Power's Ohio Assets	-	(41,762)	-
Proceeds from Sale of Assets	1,827	4,639	3,393
Net Cash Flows Used For Investing Activities	(305,883)	(279,382)	(285,259)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	244,733	89,883
Issuance of Long-term Debt – Affiliated	-	-	100,000
Change in Advances from Affiliates, Net	(16,913)	17,609	(6,517)
Retirement of Long-term Debt – Nonaffiliated	-	(36,000)	(103,245)
Principal Payments for Capital Lease Obligations	(3,022)	(3,312)	(3,933)
Dividends Paid on Common Stock	(90,000)	(114,000)	(125,000)
Net Cash Flows From (Used For) Financing Activities	(109,935)	109,030	(48,812)
Net Increase (Decrease) in Cash and Cash Equivalents	379	882	(4,084)
Cash and Cash Equivalents at Beginning of Period	940	58	4,142
Cash and Cash Equivalents at End of Period	$ 1,319	$ 940	$ 58
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 62,806	$ 54,767	$ 48,461
Net Cash Paid (Received) for Income Taxes	92,295	136,239	(5,282)
Noncash Acquisitions Under Capital Leases	2,286	998	1,302
Construction Expenditures Included in Accounts Payable at December 31,	35,627	11,254	5,955

In connection with the acquisition of the Waterford Plant in September 2005, we assumed $2.3 million of liabilities. In connection with the acquisition of Monongahela Power's Ohio assets in December 2005, we assumed $1.8 million of liabilities.

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the consolidated financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,976,947	$ 1,892,602	$ 1,741,485	$ 1,650,505	$ 1,609,047
Operating Income	$ 252,191	$ 286,660	$ 269,559	$ 204,654	$ 206,825
Income Before Cumulative Effect of Accounting Change	$ 121,168	$ 146,852	$ 133,222	$ 89,548	$ 73,992
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	(3,160)	-
Net Income	$ 121,168	$ 146,852	$ 133,222	$ 86,388	$ 73,992
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 6,226,730	$ 5,962,282	$ 5,717,480	$ 5,465,207	$ 5,209,982
Accumulated Depreciation, Depletion and Amortization	2,914,131	2,822,558	2,708,122	2,597,634	2,428,835
Net Property, Plant and Equipment	$ 3,312,599	$ 3,139,724	$ 3,009,358	$ 2,867,573	$ 2,781,147
Total Assets	$ 5,546,437	$ 5,262,309	$ 4,863,222	$ 4,654,171	$ 4,832,832
Common Shareholder’s Equity	$ 1,289,439	$ 1,220,092	$ 1,091,498	$ 1,078,047	$ 1,018,653
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 8,082	$ 8,084	$ 8,084	$ 8,101	$ 8,101
Cumulative Preferred Stock Subject to Mandatory Redemption	$ -	$ -	$ 61,445	$ 63,445	$ 64,945
Long-term Debt (a)	$ 1,555,135	$ 1,444,940	$ 1,312,843	$ 1,339,359	$ 1,617,062
Obligations Under Capital Leases (a)	$ 43,056	$ 43,976	$ 50,732	$ 37,843	$ 50,848

(a) Including portion due within one year.

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

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 582,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. We consolidate Blackhawk Coal Company and Price River Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives. Our River Transportation Division (RTD) provides barging services to affiliates and nonaffiliated companies. The revenues from barging are the majority of our other revenues.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under unit power agreements, we purchase AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Therefore, we purchase 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such 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. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO and sharing mechanisms with customers for off-system sales margins in certain areas of Michigan. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Net Income
(in millions)

Year Ended December 31, 2005		$ 147
Changes in Gross Margin:		
Retail Margins	(90)	
FERC Municipals and Cooperatives	44	
Off-system Sales	44	
Transmission Revenues	(18)	
Other	7	
Total Change in Gross Margin		(13)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(9)	
Depreciation and Amortization	(13)	
Other Income	11	
Interest Expense	(7)	
Total Change in Operating Expenses and Other		(18)
Income Tax Expense		5
Year Ended December 31, 2006		$ 121

Net Income decreased $26 million to $121 million in 2006. The key drivers of the decrease were a $13 million decrease in Gross Margin and a $13 million increase in Depreciation and Amortization.

The major components of our decrease 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 $90 million primarily due to a reduction in capacity settlement revenues of $50 million under the Interconnection Agreement and lower fuel recovery as fuel cost increases could not be recovered from customers due to the Indiana fuel cap. Capacity revenues declined due to our new peak demand in July 2006 and our affiliates' addition of generating capacity in 2005. The Indiana fuel rate cap ends July 1, 2007.
- FERC Municipals and Cooperatives margins increased $44 million due to the addition of new municipal contracts including new rates and increased demand beginning January 2006.
- Margins from Off-system Sales increased $44 million primarily due to a $41 million increase in physical sales margins and a $15 million increase in our allocation of off-system sales margins under the SIA, partially offset by a $12 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

- Transmission Revenues decreased $18 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a $6 million provision for potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other revenues increased $7 million primarily due to increased River Transportation Division (RTD) revenues for barging coal and increased gains on sales of emission allowances. Related expenses which offset the RTD revenue increase are included in Other Operation on the Consolidated Statements of Income resulting in our earning only a return approved under regulatory order.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $9 million primarily due to:
  - An $11 million increase in transmission expense due to our reduced credits under the Transmission Equalization Agreement. Our credits decreased due to our July 2006 peak and due to APCo's addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006 thus increasing the investment pool to be shared.
  - A $9 million increase in nuclear power generation expense due to the abandonment of digital turbine control equipment at the Cook Plant.
  - A $6 million increase in RTD expenses.
  - A $6 million increase reflecting a refund for the 2005 settlement of corporate owned life insurance policies.

  These increases were partially offset by:
  - A $12 million decrease in steam generation costs.
  - An $11 million decrease in distribution maintenance expense for overhead power lines including the cost of service restoration from a January 2005 ice storm and reliability initiatives.
- Depreciation and Amortization increased $13 million primarily due to higher depreciation expense related to capital additions.
- Other Income increased $11 million primarily due to an increase in interest income related to tax accrual adjustments and higher equity AFUDC.
- Interest Expense increased $7 million primarily due to an increase in outstanding long-term debt and higher interest rates.

Income Taxes

Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income and state income taxes, offset in part by tax reserve adjustments and a decrease in consolidated tax savings from Parent.

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

Off-Balance Sheet Arrangements

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

Rockport Plant Unit 2

In 1989, we, along with AEGCo, entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (Rockport 2). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. Neither we, nor AEGCo or AEP, has an ownership interest in the Owner Trustee and do not guarantee its debt.

We deferred the gain from the sale and amortize it over the term of the lease, which expires in 2022. The Owner Trustee owns Rockport 2 and leases it to AEGCo and us. We account for the lease as an operating lease with the payment obligations included in the lease footnote (see Note 14). Our future minimum lease payments are $1.2 billion as of December 31, 2006. The lease term is for 33 years with potential renewal options. At the end of the lease term, we, along with AEGCo, have the option to renew the lease or the Owner Trustee can sell Rockport 2.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 91.2	$ -	$ -	$ -	$ 91.2
Interest on Fixed Rate Portion of Long-term Debt (b)	56.0	115.0	111.0	867.0	1,149.0
Fixed Rate Portion of Long-term Debt (c)	50.0	50.0	-	1,197.0	1,297.0
Variable Rate Portion of Long-term Debt (d)	-	45.0	-	217.0	262.0
Capital Lease Obligations (e)	17.1	13.1	4.7	19.2	54.1
Noncancelable Operating Leases (e)	98.9	194.9	184.8	873.8	1,352.4
Fuel Purchase Contracts (f)	284.1	470.7	326.9	172.7	1,254.4
Energy and Capacity Purchase Contracts (g)	2.1	3.2	4.7	1.0	11.0
Construction Contracts for Capital Assets (h)	73.0	52.0	18.7	0.9	144.6
Total	$ 672.4	$ 943.9	$ 650.8	$ 3,348.6	$ 5,615.7

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.50% and 3.90% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

Cook Plant

In 2006, during a regular refueling outage, Cook Plant Unit 1 completed the planned replacement of major components, including the reactor vessel head, at a cost of $119 million. These improvements and replacement of major components should increase efficiency as well as adding 40 MW of capacity in the winter. We refueled Cook Plant Unit 2 during March and April 2006 and plan to replace its vessel head during its next refueling outage scheduled for the fall of 2007.

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 their eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 Consolidated Balance Sheet as of December 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 Consolidated Balance Sheet As of December 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 63,765	$ 5,987	$ -	$ 69,752
Noncurrent Assets	59,053	84	-	59,137
Total MTM Derivative Contract Assets	122,818	6,071	-	128,889
Current Liabilities	(49,897)	(585)	(1,601)	(52,083)
Noncurrent Liabilities	(36,707)	(18)	(5,916)	(42,641)
Total MTM Derivative Contract Liabilities	(86,604)	(603)	(7,517)	(94,724)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 36,214	$ 5,468	$ (7,517)	$ 34,165

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 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	(1,010)
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	(146)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(557)
Changes Due to SIA Agreement (c)	(3,940)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	7,935
Total MTM Risk Management Contract Net Assets	36,214
Net Cash Flow Hedge Contracts	5,468
DETM Assignment (e)	(7,517)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 34,165

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.
(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in our Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See “Natural Gas Contracts with DETM” section of Note 16.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 3,502	$ 2,515	$ 432	$ -	$ -	$ -	$ 6,449
Prices Provided by Other External Sources – OTC Broker Quotes (a)	10,919	3,476	5,037	-	-	-	19,432
Prices Based on Models and Other Valuation Methods (b)	(551)	768	2,585	5,780	761	990	10,333
Total	$ 13,870	$ 6,759	$ 8,054	$ 5,780	$ 761	$ 990	$ 36,214

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

We use interest rate derivative transactions to manage interest rate risk related to 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (877)	$ (2,590)	$ (3,467)
Changes in Fair Value	3,603	(10,179)	(6,576)
Impact due to Changes in SIA (a)	(267)	-	(267)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	1,112	236	1,348
Ending Balance in AOCI December 31, 2006	$ 3,571	$ (12,533)	$ (8,962)

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,521 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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$506	$1,283	$418	$240	$433	$720	$343	$124

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

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 $93 million and $55 million at December 31, 2006 and 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
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,601,135	$ 1,445,866	$ 1,378,844
Sales to AEP Affiliates	291,033	366,032	286,310
Other – Affiliated	52,598	46,719	42,968
Other – Nonaffiliated	32,181	33,985	33,363
TOTAL	1,976,947	1,892,602	1,741,485
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	373,741	327,263	286,211
Purchased Electricity for Resale	62,098	48,378	37,013
Purchased Electricity from AEP Affiliates	343,156	306,117	272,452
Other Operation	472,404	451,553	458,820
Maintenance	190,866	202,909	168,304
Depreciation and Amortization	208,633	196,037	186,513
Taxes Other Than Income Taxes	73,858	73,685	62,613
TOTAL	1,724,756	1,605,942	1,471,926
OPERATING INCOME	252,191	286,660	269,559
Other Income (Expense):			
Interest Income	9,868	2,006	2,011
Allowance for Equity Funds Used During Construction	7,937	4,457	2,338
Interest Expense	(72,723)	(65,041)	(69,071)
INCOME BEFORE INCOME TAXES	197,273	228,082	204,837
Income Tax Expense	76,105	81,230	71,615
NET INCOME	121,168	146,852	133,222
Preferred Stock Dividend Requirements including Capital Stock Expense and Other	339	395	474
EARNINGS APPLICABLE TO COMMON STOCK	$ 120,829	$ 146,457	$ 132,748

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

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 56,584	$ 858,694	$ 187,875	$ (25,106)	$ 1,078,047
Common Stock Dividends			(99,293)		(99,293)
Preferred Stock Dividends			(340)		(340)
Capital Stock Expense		141	(134)		7
TOTAL					978,421
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,314				(4,298)	(4,298)
Minimum Pension Liability, Net of Tax of $8,533				(15,847)	(15,847)
NET INCOME			133,222		133,222
TOTAL COMPREHENSIVE INCOME					113,077
DECEMBER 31, 2004	56,584	858,835	221,330	(45,251)	1,091,498
Common Stock Dividends			(62,000)		(62,000)
Preferred Stock Dividends			(339)		(339)
Capital Stock Expense and Other		2,455	(56)		2,399
TOTAL					1,031,558
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $328				609	609
Minimum Pension Liability, Net of Tax of $22,116				41,073	41,073
NET INCOME			146,852		146,852
TOTAL COMPREHENSIVE INCOME					188,534
DECEMBER 31, 2005	56,584	861,290	305,787	(3,569)	1,220,092
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(339)		(339)
TOTAL					1,179,753
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,959				(5,495)	(5,495)
Minimum Pension Liability, Net of Tax of $70				(129)	(129)
NET INCOME			121,168		121,168
TOTAL COMPREHENSIVE INCOME					115,544
Minimum Pension Liability Elimination, Net of Tax of $124				231	231
SFAS 158 Adoption, Net of Tax of $3,278				(6,089)	(6,089)
DECEMBER 31, 2006	$ 56,584	$ 861,290	$ 386,616	$ (15,051)	$ 1,289,439

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

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

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,369	$ 854
Accounts Receivable:		
Customers	84,308	62,614
Affiliated Companies	108,288	127,981
Miscellaneous	1,838	1,982
Allowance for Uncollectible Accounts	(601)	(898)
Total Accounts Receivable	193,833	191,679
Fuel	64,669	25,894
Materials and Supplies	129,953	118,039
Risk Management Assets	69,752	78,134
Accrued Tax Benefits	27,378	51,846
Prepayments and Other	15,170	31,303
TOTAL	502,124	497,749
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,363,813	3,128,078
Transmission	1,047,264	1,028,496
Distribution	1,102,033	1,029,498
Other (including nuclear fuel and coal mining)	529,727	465,130
Construction Work in Progress	183,893	311,080
Total	6,226,730	5,962,282
Accumulated Depreciation, Depletion and Amortization	2,914,131	2,822,558
TOTAL - NET	3,312,599	3,139,724
OTHER NONCURRENT ASSETS		
Regulatory Assets	314,805	222,686
Spent Nuclear Fuel and Decommissioning Trusts	1,248,319	1,133,567
Long-term Risk Management Assets	59,137	103,645
Deferred Charges and Other	109,453	164,938
TOTAL	1,731,714	1,624,836
TOTAL ASSETS	$ 5,546,437	$ 5,262,309

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 91,173	$ 93,702
Accounts Payable:		
General	146,733	139,334
Affiliated Companies	65,497	60,324
Long-term Debt Due Within One Year – Nonaffiliated	50,000	364,469
Risk Management Liabilities	52,083	71,032
Customer Deposits	34,946	49,258
Accrued Taxes	59,652	56,567
Other	128,461	112,839
TOTAL	628,545	947,525
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,505,135	1,080,471
Long-term Risk Management Liabilities	42,641	86,159
Deferred Income Taxes	335,000	335,264
Regulatory Liabilities and Deferred Investment Tax Credits	753,402	710,015
Asset Retirement Obligations	809,853	737,959
Deferred Credits and Other	174,340	136,740
TOTAL	3,620,371	3,086,608
TOTAL LIABILITIES	4,248,916	4,034,133
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,082	8,084
Commitments and Contingencies (Note 6)		
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	386,616	305,787
Accumulated Other Comprehensive Income (Loss)	(15,051)	(3,569)
TOTAL	1,289,439	1,220,092
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,546,437	$ 5,262,309

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 121,168	$ 146,852	$ 133,222
Adjustments for Noncash Items:			
Depreciation and Amortization	208,633	196,037	186,513
Deferred Income Taxes	13,626	26,873	(5,548)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(23,893)	21,273	13,082
Amortization of Nuclear Fuel	50,313	56,038	52,455
Mark-to-Market of Risk Management Contracts	(2,059)	(7,331)	2,756
Pension Contributions to Qualified Plan Trusts	-	(90,668)	(3,888)
Change in Other Noncurrent Assets	4,809	12,990	10,322
Change in Other Noncurrent Liabilities	26,822	22,288	40,875
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(2,154)	(785)	983
Fuel, Materials and Supplies	(50,689)	(13,373)	(10,977)
Accounts Payable	37,651	9,630	(1,304)
Customer Deposits	(14,312)	19,892	7,411
Accrued Taxes, Net	27,553	(118,438)	80,970
Other Current Assets	16,208	(14,608)	(2,167)
Other Current Liabilities	11,951	25,476	6,198
Net Cash Flows From Operating Activities	425,627	292,146	510,903
INVESTING ACTIVITIES			
Construction Expenditures	(325,390)	(298,632)	(179,414)
Change in Advances to Affiliates, Net	-	5,093	(5,093)
Purchases of Investment Securities	(691,956)	(606,936)	(901,356)
Sales of Investment Securities	630,555	556,667	862,976
Acquisitions of Nuclear Fuel	(89,100)	(52,579)	(50,865)
Other	6,458	16,794	2,788
Net Cash Flows Used For Investing Activities	(469,433)	(379,593)	(270,964)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	443,743	123,761	268,057
Change in Advances from Affiliates, Net	(2,529)	93,702	(98,822)
Retirement of Long-term Debt – Nonaffiliated	(350,000)	-	(304,017)
Retirement of Cumulative Preferred Stock	(1)	(61,445)	(2,011)
Principal Payments for Capital Lease Obligations	(6,553)	(5,889)	(6,916)
Dividends Paid on Common Stock	(40,000)	(62,000)	(99,293)
Dividends Paid on Cumulative Preferred Stock	(339)	(339)	(340)
Net Cash Flows From (Used For) Financing Activities	44,321	87,790	(243,342)
Net Increase (Decrease) in Cash and Cash Equivalents	515	343	(3,403)
Cash and Cash Equivalents at Beginning of Period	854	511	3,914
Cash and Cash Equivalents at End of Period	$ 1,369	$ 854	$ 511
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 84,354	$ 59,339	$ 70,988
Net Cash Paid (Received) for Income Taxes	56,506	184,061	(2,244)
Noncash Acquisitions Under Capital Leases	5,968	2,639	20,557
Construction Expenditures Included in Accounts Payable at December 31,	37,287	38,523	16,530
Noncash Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	210	24,053	-

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the consolidated financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 585,867	$ 531,343	$ 448,961	$ 412,667	$ 391,516
Operating Income	$ 81,625	$ 60,831	$ 63,339	$ 70,749	$ 57,579
Income Before Cumulative Effect of Accounting Change	$ 35,035	$ 20,809	$ 25,905	$ 33,464	$ 20,567
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	(1,134)	-
Net Income	$ 35,035	$ 20,809	$ 25,905	$ 32,330	$ 20,567
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,445,133	$ 1,414,426	$ 1,367,138	$ 1,355,315	$ 1,301,332
Accumulated Depreciation and Amortization	442,778	425,817	398,608	382,022	373,874
Net Property, Plant and Equipment	$ 1,002,355	$ 988,609	$ 968,530	$ 973,293	$ 927,458
Total Assets	$ 1,310,565	$ 1,320,026	$ 1,243,247	$ 1,221,634	$ 1,188,342
Common Shareholder's Equity	$ 369,651	$ 347,841	$ 320,980	$ 317,138	$ 298,018
Long-term Debt (a)	$ 446,968	$ 486,990	$ 508,310	$ 487,602	$ 466,632
Obligations Under Capital Leases (a)	$ 2,647	$ 3,168	$ 4,363	$ 5,292	$ 7,248

(a) Including portion due within one year.

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, we purchase 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, we purchase 390 MW of Rockport Plant capacity. The unit power agreement expires in December 2022. We pay a demand charge for the right to receive the power, which is payable even if the power is not taken.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such 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. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO and sharing mechanisms with customers for off-system sales margins in Kentucky. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Net Income
(in millions)

Year Ended December 31, 2005		$	21
Changes in Gross Margin:			
Retail Margins	21		
Off-system Sales	13		
Transmission Revenues	(10)		
Other	4		
Total Change in Gross Margin			28
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(7)		
Depreciation and Amortization	(1)		
Taxes Other Than Income Taxes	1		
Total Change in Operating Expenses and Other			(7)
Income Tax Expense			(7)
Year Ended December 31, 2006		$	35

Net Income increased $14 million to $35 million in 2006. The key driver of the increase was a $28 million increase in Gross Margin, partially offset by an increase in Other Operation and Maintenance expenses of $7 million and an increase in Income Tax Expense of $7 million.

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 $21 million primarily due to rate relief of $33 million from the March 2006 approval of the settlement agreement in our base rate case. The above was partially offset by a $6 million decrease related to increased credits to retail customers of a portion of off-system sales margins due to higher off-system sales. Another partial offset is a result of increased capacity charges of $4 million due to changes in the relative peak demands and generating capacity of the AEP Power Pool members.
- Margins from Off-system Sales increased $13 million primarily due to a $12 million increase in physical sales margins and a $6 million increase in our allocation of off-system sales margins under the SIA, offset by a $5 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.
- Transmission Revenues decreased $10 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $3 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the “Transmission Rate Proceedings at the FERC” section of Note 4.
- Other revenues increased $4 million primarily due to a $3 million unfavorable adjustment of the Demand Side Management Program regulatory asset in March 2005.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $7 million primarily due to maintenance of overhead lines as well as an increase in transmission costs associated with the Transmission Equalization Agreement. This increase in transmission costs was due to the addition of the Wyoming-Jacksons Ferry 765 kV line which was energized and placed into service in June 2006.

Income Taxes

Income Tax Expense increased $7 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 are as follows:

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

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 30.6	$ -	$ -	$ -	$ 30.6
Interest on Fixed Rate Portion of Long-term Debt (b)	24.0	13.0	11.0	92.0	140.0
Fixed Rate Portion of Long-term Debt (c)	322.0	30.0	-	95.0	447.0
Capital Lease Obligations (d)	1.2	1.2	0.4	0.1	2.9
Noncancelable Operating Leases (d)	2.1	3.2	2.3	2.3	9.9
Fuel Purchase Contracts (e)	81.8	28.6	7.9	22.5	140.8
Energy and Capacity Purchase Contracts (f)	0.7	1.1	1.7	0.3	3.8
Construction Contracts for Capital Assets (g)	30.0	10.0	-	41.1	81.1
Total	$ 492.4	$ 87.1	$ 23.3	$ 253.3	$ 856.1

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 14.
(e) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

Significant Factors

Big Sandy Plant Scrubber

Completion of construction of a scrubber at our Big Sandy Plant was previously scheduled for 2010. We suspended the project in the second quarter of 2006 after a generation engineering evaluation determined that there was a substantially higher estimated capital cost due to increases in labor and material costs, refinements of preliminary costs estimates and an increase in cost per ton of removed SO_2. We currently estimate the project to have an in-service date of 2014 or beyond. Management continues to review its emission compliance plans given changing market conditions and the evolving legislative and regulatory environment.

We transferred the total project expenditures of $17 million during 2006 from Construction Work in Progress to Deferred Charges and Other on our Balance Sheet. If management does not resume the project, the balance of incurred expenditures would negatively impact future earnings unless a regulatory asset could be established due to probable recovery through rates.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have 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" 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 balance sheet as of December 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 Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 23,049	$ 2,575	$ -	$ 25,624
Noncurrent Assets	21,252	30	-	21,282
Total MTM Derivative Contract Assets	44,301	2,605	-	46,906
Current Liabilities	(18,302)	(1,126)	(573)	(20,001)
Noncurrent Liabilities	(13,301)	(6)	(2,119)	(15,426)
Total MTM Derivative Contract Liabilities	(31,603)	(1,132)	(2,692)	(35,427)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,698	$ 1,473	$ (2,692)	$ 11,479

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 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		(225)
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		(62)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(553)
Changes Due to SIA Agreement (c)		(1,565)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		1,585
Total MTM Risk Management Contract Net Assets		12,698
Net Cash Flow & Fair Value Hedge Contracts		1,473
DETM Assignment (e)		(2,692)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$	11,479

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.
(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See “Natural Gas Contracts with DETM” section of Note 16.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 1,281	$ 917	$ 155	$ -	$ -	$ -	$ 2,353
Prices Provided by Other External Sources – OTC Broker Quotes (a)	3,820	1,243	1,804	-	-	-	6,867
Prices Based on Models and Other Valuation Methods (b)	(355)	210	926	2,070	273	354	3,478
Total	$ 4,746	$ 2,370	$ 2,885	$ 2,070	$ 273	$ 354	$ 12,698

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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

We use interest rate derivative transactions to manage interest rate risk related to 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 Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (352)	$ 158	$ (194)
Changes in Fair Value	1,295	201	1,496
Impact due to Changes in SIA (a)	(106)	-	(106)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	442	(86)	356
Ending Balance in AOCI December 31, 2006	$ 1,279	$ 273	$ 1,552

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,340 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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$181	$459	$158	$86	$174	$289	$138	$50

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

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 $13 million at December 31, 2006 and 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.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 526,432	$ 458,858	$ 397,581
Sales to AEP Affiliates	58,287	70,803	48,717
Other	1,148	1,682	2,663
TOTAL	585,867	531,343	448,961
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	152,335	142,672	103,881
Purchased Electricity for Resale	8,724	7,213	3,407
Purchased Electricity from AEP Affiliates	192,080	176,350	140,758
Other Operation	60,674	59,024	51,782
Maintenance	35,430	30,652	32,802
Depreciation and Amortization	46,387	45,110	43,847
Taxes Other Than Income Taxes	8,612	9,491	9,145
TOTAL	504,242	470,512	385,622
OPERATING INCOME	81,625	60,831	63,339
Other Income (Expense):			
Interest Income	656	880	462
Allowance for Equity Funds Used During Construction	241	305	245
Interest Expense	(28,832)	(29,071)	(29,470)
INCOME BEFORE INCOME TAXES	53,690	32,945	34,576
Income Tax Expense	18,655	12,136	8,671
NET INCOME	$ 35,035	$ 20,809	$ 25,905

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

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

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 50,450	$ 208,750	$ 64,151	$ (6,213)	$ 317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL					297,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $212				393	393
Minimum Pension Liability, Net of Tax of $1,592				(2,955)	(2,955)
NET INCOME			25,905		25,905
TOTAL COMPREHENSIVE INCOME					23,343
DECEMBER 31, 2004	50,450	208,750	70,555	(8,775)	320,980
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	50,450	208,750	88,864	(223)	347,841
Common Stock Dividends			(15,000)		(15,000)
TOTAL					332,841
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				1,746	1,746
Minimum Pension Liability, Net of Tax of $16				29	29
NET INCOME			35,035		35,035
TOTAL COMPREHENSIVE INCOME					36,810
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651

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

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

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 702	$ 526
Accounts Receivable:		
Customers	30,112	26,533
Affiliated Companies	10,540	23,525
Accrued Unbilled Revenues	3,602	6,311
Miscellaneous	327	35
Allowance for Uncollectible Accounts	(227)	(147)
Total Accounts Receivable	44,354	56,257
Fuel	16,070	8,490
Materials and Supplies	8,726	10,181
Risk Management Assets	25,624	31,437
Accrued Tax Benefits	1,021	6,598
Margin Deposits	2,923	6,895
Prepayments and Other	2,425	6,324
TOTAL	101,845	126,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	478,955	472,575
Transmission	394,419	386,945
Distribution	481,083	456,063
Other	61,089	63,382
Construction Work in Progress	29,587	35,461
Total	1,445,133	1,414,426
Accumulated Depreciation and Amortization	442,778	425,817
TOTAL - NET	1,002,355	988,609
OTHER NONCURRENT ASSETS		
Regulatory Assets	136,139	117,432
Long-term Risk Management Assets	21,282	41,810
Deferred Charges and Other	48,944	45,467
TOTAL	206,365	204,709
TOTAL ASSETS	$ 1,310,565	$ 1,320,026

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

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2006 and 2005

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 30,636	$ 6,040
Accounts Payable:		
General	31,490	32,454
Affiliated Companies	23,658	29,326
Long-term Debt Due Within One Year – Nonaffiliated	322,048	-
Long-term Debt Due Within One Year – Affiliated	-	39,771
Risk Management Liabilities	20,001	28,770
Customer Deposits	16,095	21,643
Accrued Taxes	18,775	8,805
Other	26,303	21,524
TOTAL	489,006	188,333
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	104,920	427,219
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	15,426	35,302
Deferred Income Taxes	242,133	234,719
Regulatory Liabilities and Deferred Investment Tax Credits	49,109	56,794
Deferred Credits and Other	20,320	9,818
TOTAL	451,908	783,852
TOTAL LIABILITIES	940,914	972,185
Commitments and Contingencies (Note 6)		
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	108,899	88,864
Accumulated Other Comprehensive Income (Loss)	1,552	(223)
TOTAL	369,651	347,841
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,310,565	$ 1,320,026

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

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 35,035	$ 20,809	$ 25,905
Adjustments for Noncash Items:			
Depreciation and Amortization	46,387	45,110	43,847
Deferred Income Taxes	2,596	10,555	12,774
Mark-to-Market of Risk Management Contracts	580	(3,465)	1,020
Pension Contributions to Qualified Plan Trusts	-	(18,894)	(451)
Change in Other Noncurrent Assets	(4,738)	(419)	(6,902)
Change in Other Noncurrent Liabilities	2,621	3,844	9,126
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	11,903	(3,681)	(1,177)
Fuel, Materials and Supplies	(6,125)	(2,735)	2,724
Accounts Payable	(3,436)	13,184	(1,745)
Customer Deposits	(5,548)	9,334	2,415
Accrued Taxes, Net	15,547	(7,041)	1,919
Other Current Assets	7,867	(9,261)	474
Other Current Liabilities	3,953	1,589	65
Net Cash Flows From Operating Activities	106,642	58,929	89,994
INVESTING ACTIVITIES			
Construction Expenditures	(77,848)	(56,979)	(36,957)
Change in Other Cash Deposits, Net	5	(5)	-
Change in Advances to Affiliates, Net	-	16,127	(16,127)
Proceeds from Sales of Assets	2,956	300	1,538
Net Cash Flows Used For Investing Activities	(74,887)	(40,557)	(51,546)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Affiliated	-	-	20,000
Change in Advances from Affiliates, Net	24,596	6,040	(38,096)
Retirement of Long-term Debt – Affiliated	(40,000)	(20,000)	-
Principal Payments for Capital Lease Obligations	(1,175)	(1,518)	(1,605)
Dividends Paid on Common Stock	(15,000)	(2,500)	(19,501)
Net Cash Flows Used For Financing Activities	(31,579)	(17,978)	(39,202)
Net Increase (Decrease) in Cash and Cash Equivalents	176	394	(754)
Cash and Cash Equivalents at Beginning of Period	526	132	886
Cash and Cash Equivalents at End of Period	$ 702	$ 526	$ 132
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,887	$ 27,354	$ 28,367
Net Cash Paid (Received) for Income Taxes	11,516	11,655	(3,233)
Noncash Acquisitions Under Capital Leases	648	419	925
Construction Expenditures Included in Accounts Payable at December 31,	3,357	6,553	2,936

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2006 and 2005, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 2,724,875	$ 2,634,549	$ 2,372,725	$ 2,250,132	$ 2,163,082
Operating Income	$ 425,291	$ 425,487	$ 419,539	$ 491,844	$ 433,983
Income Before Cumulative Effect of Accounting Changes	$ 228,643	$ 250,419	$ 210,116	$ 251,031	$ 220,023
Cumulative Effect of Accounting Changes, Net of Tax	-	(4,575)	-	124,632	-
Net Income	$ 228,643	$ 245,844	$ 210,116	$ 375,663	$ 220,023
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 8,405,645	$ 7,523,288	$ 6,858,771	$ 6,575,577	$ 5,732,008
Accumulated Depreciation and Amortization	2,836,584	2,738,899	2,633,203	2,500,918	2,486,982
Net Property, Plant and Equipment	$ 5,569,061	$ 4,784,389	$ 4,225,568	$ 4,074,659	$ 3,245,026
Total Assets (a)	$ 6,818,733	$ 6,330,670	$ 5,593,265	$ 5,374,518	$ 4,554,023
Common Shareholder’s Equity	$ 2,008,342	$ 1,767,947	$ 1,473,838	$ 1,464,025	$ 1,233,114
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 16,630	$ 16,639	$ 16,641	$ 16,645	$ 16,648
Cumulative Preferred Stock Subject to Mandatory Redemption	$ -	$ -	$ 5,000	$ 7,250	$ 8,850
Long-term Debt (a)(b)	$ 2,401,741	$ 2,199,670	$ 2,011,060	$ 2,039,940	$ 1,067,314
Obligations Under Capital Leases (b)	$ 34,966	$ 39,924	$ 40,733	$ 34,688	$ 65,626

(a) Due to the implementation of FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003.
(b) Including portion due within one year.

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We consolidate JMG Funding LP, a variable interest entity. As a member of the AEP Power Pool, we share in the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such 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. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints of operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$ 250
Changes in Gross Margin:		
Retail Margins	59	
Off-system Sales	55	
Transmission Revenues	(32)	
Other	3	
Total Change in Gross Margin		85
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(63)	
Depreciation and Amortization	(19)	
Taxes Other Than Income Taxes	(2)	
Carrying Costs Income	(35)	
Interest Expense	6	
Total Change in Operating Expenses and Other		(113)
Income Tax Expense		7
Year Ended December 31, 2006		$ 229

Income Before Cumulative Effect of Accounting Change decreased $21 million to $229 million in 2006. The key driver of the decrease was a $113 million increase in Operating Expenses and Other partially offset by an $85 million increase in Gross Margin.

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 $59 million primarily due to the following:
  - A $120 million increase related to the RSP rate increase effective January 1, 2006.
  - A $20 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak.
  - An $11 million decrease in allowance expenses driven by a decrease in the average unit price of allowances.
  - A $6 million decrease in consumables primarily due to a decrease in commodity prices.

  These increases were partially offset by:
  - An $87 million decrease related to a decrease in fuel margins primarily due to higher fuel costs and a decrease in industrial revenue due to the transfer of a significant customer to an affiliate.
  - An $8 million decrease in revenues associated with SO_2 allowances received from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement.

- Margins from Off-system Sales increased $55 million primarily due to a $70 million increase in physical sales margins and a $20 million increase in our allocation of off-system sales margins under the SIA offset by a $35 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the “Allocation Agreement between AEP East companies and AEP West companies” section of Note 4. Margins from Off-system Sales also increased as a result of decreased fuel costs and favorable optimization activities related to our purchase power and sale agreement with the Dow Chemical Company (Dow). This increase in margin related to Dow was offset by a corresponding increase in Other Operation and Maintenance expenses. See “Plaquemine Cogeneration Facility” section of “Significant Factors” for additional discussion of Dow.
- Transmission Revenues decreased $32 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $8 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the “Transmission Rate Proceedings at the FERC” section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $63 million primarily due to the following:
  - A $30 million increase in maintenance from planned and forced outages at the Gavin, Muskingum River, Kammer and Sporn plants related to major boiler and turbine overhauls and boiler tube inspections.
  - A $21 million unfavorable variance due to increased maintenance costs and increased rental expense related to our purchase power and sale agreement with Dow. These increases in Other Operation and Maintenance expenses, which includes an indemnification adjustment related to our purchase power and sale agreement with Dow were offset by a corresponding increase in margins from Off-system Sales. See “Plaquemine Cogeneration Facility” section of “Significant Factors” for additional discussion of Dow.
  - An $8 million increase in removal costs related to maintenance.

  These increases were partially offset by:
  - A $10 million variance due to the reduction of liabilities related to sold coal companies.
- Depreciation and Amortization increased $19 million primarily due to a $17 million increase in amortization of regulatory assets partially offset by the 2005 establishment of a $7 million regulatory liability to benefit low-income customers and for economic development, as ordered in our RSP. In addition, an $8 million increase in depreciation is attributable to a higher depreciable base in electric utility assets.
- Carrying Costs Income decreased $35 million primarily due to the completion of deferrals of the environmental carrying costs from 2004 and 2005 that are now being recovered during 2006 through 2008 according to the RSP.
- Interest Expense decreased $6 million primarily due to a $26 million increase in AFUDC partially offset by a $17 million increase in interest due to long-term debt issuances since November 2005.

Income Taxes

Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income and state income taxes offset in part by tax return and tax reserve adjustments and changes in certain book/tax differences accounted for on a flow-through basis.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 210
Changes in Gross Margin:		
Retail Margins	35	
Off-system Sales	45	
Transmission Revenues	(15)	
Other	1	
Total Change in Gross Margin		66
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(32)	
Depreciation and Amortization	(16)	
Taxes Other Than Income Taxes	(12)	
Carrying Costs Income	48	
Interest Expense	15	
Total Change in Operating Expenses and Other		3
Income Tax Expense		(29)
Year Ended December 31, 2005		$ 250

Income Before Cumulative Effect of Accounting Change increased by $40 million in 2005. The key drivers of the increase were a $66 million increase in Gross Margin and a $48 million increase in Carrying Costs Income partially offset by a $32 million increase in Other Operation and Maintenance expenses and a $29 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 were $35 million higher than the prior period primarily due to:
  - A $44 million increase in retail sales primarily due to increased residential, commercial and industrial sales from higher usage and favorable weather conditions.
  - An $18 million favorable variance primarily due to the receipt of SO_2 allowances from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement.
  - A $7 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate's peak.

  These increases were partially offset by:
  - An $18 million decrease in fuel margins partially due to an amendment to the PJM Services and Cost Allocation Agreement and the Buckeye Station Agreement of $9 million.
- Off-system Sales increased $45 million primarily due to increased AEP Power Pool physical sales and our purchase power and sale agreement with Dow. The increase in margin related to Dow was offset by a corresponding increase in Other Operation and Maintenance expenses. See "Plaquemine Cogeneration Facility" section of "Significant Factors" for additional discussion of Dow.
- Transmission Revenues decreased $15 million primarily due to the loss of through-and-out rates, net of replacement SECA rates. See "Transmission Rate Proceedings at the FERC" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $32 million primarily due to increased planned outages and maintenance on several units, maintenance of overhead lines due to increased tree trimming expenses and decreased expenses in 2004 as a result of a settlement related to the sale of the coal companies prior to 2003. These increases were partially offset by the settlement and cancellation of the COLI (corporate owned life insurance) policy in February 2005 and decreased administrative expenses related to the Gavin scrubber. Other Operation and Maintenance expenses also increased due to increased maintenance and rental expenses related to our purchase power and sale agreement with Dow. These increases in Other Operation and Maintenance expenses, which includes an indemnification adjustment related to Dow were offset by a corresponding increase in margins from Off-system Sales. See “Plaquemine Cogeneration Facility” section of “Significant Factors” for additional discussion of Dow.
- Depreciation and Amortization expense increased $16 million due to the establishment of a $7 million regulatory liability to benefit low-income customers and for economic development, as ordered in our RSP. The increase is also attributable to a higher depreciation base in electric utility plants.
- Taxes Other Than Income Taxes increased $12 million primarily due to an increase in property tax accruals as a result of increased property values. The increase is also a result of increased state excise taxes due to higher taxable KWH sales.
- Carrying Costs Income increased $48 million primarily due to the carrying costs on environmental capital expenditures as a result of our RSP order.
- Interest Expense decreased $15 million primarily due to capitalized interest related to construction of the Mitchell Plant and Cardinal Plant scrubbers and the Mitchell Plant SCR project that began after June 2004. Interest Expense also decreased due to optional redemptions and subsequent refinancings with lower cost debt.

Income Taxes

Income Tax Expense increased $29 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 are as follows:

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

Cash Flow

Cash flows for 2006, 2005 and 2004 were as follows:

	2006	2005	2004
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,240	$ 9,337	$ 7,294
Cash Flows From (Used For):			
Operating Activities	626,246	368,805	545,855
Investing Activities	(986,095)	(571,184)	(324,392)
Financing Activities	360,234	194,282	(219,420)
Net Increase (Decrease) in Cash and Cash Equivalents	385	(8,097)	2,043
Cash and Cash Equivalents at End of Period	$ 1,625	$ 1,240	$ 9,337

Operating Activities

Net Cash Flows From Operating Activities were $626 million in 2006. We produced Net Income of $229 million during the period and a noncash expense item of $322 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, including a $116 million decrease in Accounts Receivable, Net. Accounts Receivable, Net decreased due to the collection of receivables related to power sales to affiliates, settled litigation and emission allowances.

Net Cash Flows From Operating Activities were $369 million in 2005. We produced Net Income of $246 million during the period and a noncash expense item of $302 million for Depreciation and Amortization. We made contributions of $132 million to our pension trust fund. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items including a $114 million decrease in Accrued Taxes, Net. During 2005, we made federal income tax payments of $198 million.

Net Cash Flows From Operating Activities were $546 million in 2004. We produced Net Income of $210 million during the period and noncash expense items of $286 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, including a $100 million increase in Accrued Taxes, Net. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment was made in March 2005 when the 2004 federal income tax return extension was filed.

Investing Activities

Our net cash flows used for investing activities in 2006, 2005 and 2004 were $986 million, $571 million and $324 million, respectively, primarily due to Construction Expenditures for environmental upgrades, as well as projects to improve service reliability for transmission and distribution.

Financing Activities

Net Cash Flows From Financing Activities were $360 million in 2006. We issued $350 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. We received a capital contribution from our Parent Company of $70 million. These amounts were partially offset by a $200 million retirement of affiliated notes payable.

Net Cash Flows From Financing Activities were $194 million in 2005. We issued $353 million of Pollution Control Bonds and $200 million of Senior Unsecured Notes. These amounts were partially offset by a $353 million retirement of Pollution Control Bonds.

Net Cash Flows Used For Financing Activities were $219 million in 2004. We retired $363 million of Senior Unsecured Notes Payable and paid $174 million dividends on common stock. These amounts were partially offset by a $400 million long-term debt issuance from AEP.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 1.2	$ -	$ -	$ -	$ 1.2
Advances from Affiliates (b)	181.3	-	-	-	181.3
Interest on Fixed Rate Portion of Long-term Debt (c)	112.0	217.0	194.0	910.0	1,433.0
Fixed Rate Portion of Long-term Debt (d)	18.0	133.0	200.0	1,589.0	1,940.0
Variable Rate Portion of Long-term Debt (e)	-	-	-	468.0	468.0
Capital Lease Obligations (f)	9.3	12.2	5.9	20.9	48.3
Noncancelable Operating Leases (f)	21.3	37.4	31.6	71.0	161.3
Fuel Purchase Contracts (g)	761.2	1,280.2	1,227.9	3,604.5	6,873.8
Energy and Capacity Purchase Contracts (h)	2.4	3.6	5.4	1.1	12.5
Construction Contracts for Capital Assets (i)	626.5	41.0	-	124.1	791.6
Total	$ 1,733.2	$ 1,724.4	$ 1,664.8	$ 6,788.6	$ 11,911.0

(a) Represents principal only excluding interest.
(b) Represents short-term borrowing from the Utility Money Pool.
(c) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(d) See Note 15. Represents principal only excluding interest.
(e) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.60% and 3.85% at December 31, 2006.
(f) See Note 14.
(g) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(h) Represents contractual cash flows of energy and capacity purchase contracts.
(i) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

Significant Factors

Plaquemine Cogeneration Facility

In 2000, Juniper Capital L.P. financed AEP's nonregulated ownership interest in the Plaquemine Cogeneration Facility (the Facility) near Plaquemine, Louisiana. AEP subleased the Facility to Dow Chemical Company (Dow). As outlined in the "OPCo Indemnification Agreement with AEP Resources" section of Note 16, we entered into a purchase power and sale agreement with Dow and a corresponding indemnification agreement with a nonutility subsidiary of AEP. As a result, our results of operations included sales to nonaffiliated companies and offsetting maintenance expense with no effect on our Net Income. In the fourth quarter of 2006, AEP sold the Facility to Dow. With the sale of the Facility, we terminated our purchase power and sale agreement with Dow. This sale did not have an impact on our 2006 results of operations. In 2006, the operation of the facility affected revenues, Fuel and Other Consumables Used for Electric Generation, Purchased Electricity for Resale, Other Operation expense and Maintenance expense by approximately $157 million, $134 million, ($7) million, $19 million and $11 million, respectively, with no effect on net income. These revenues and expenses will not recur in 2007.

Muskingum River Project Deferral

Completion of construction of the Muskingum River Unit 5 flue gas desulfurization (FGD) project was previously scheduled for 2008. We suspended the project in 2006 following a review of a new SO_2 and mercury compliance plan evaluation, updated coal market information reflecting the contraction of the low sulfur price differentials and the latest project costs. We currently estimate the project to have an in-service date in 2014 or beyond. Management continues to review its emission compliance plans given changing market conditions and the evolving legislative and regulatory environment.

We transferred the total project expenditures of $33 million from Construction Work in Progress to Deferred Charges and Other on our Consolidated Balance Sheet. If management does not resume the project, the balance of incurred expenditures would negatively impact future earnings unless a regulatory asset could be established due to probable recovery through rates.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have 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" 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 balance sheet as of December 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
Consolidated Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 80,175	$ 6,772	$ -	$ 86,947
Noncurrent Assets	69,997	95	-	70,092
Total MTM Derivative Contract Assets	150,172	6,867	-	157,039
Current Liabilities	(70,913)	(662)	(1,811)	(73,386)
Noncurrent Liabilities	(46,217)	(20)	(6,692)	(52,929)
Total MTM Derivative Contract Liabilities	(117,130)	(682)	(8,503)	(126,315)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,042	$ 6,185	$ (8,503)	$ 30,724

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 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		(5,340)
Fair Value of New Contracts at Inception When Entered During the Period (a)		713
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(486)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		451
Changes in Fair Value Due to Market Fluctuations During the Period (b)		1,460
Changes Due to SIA Agreement (c)		(4,984)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		334
Total MTM Risk Management Contract Net Assets		33,042
Net Cash Flow Hedge Contracts		6,185
DETM Assignment (e)		(8,503)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$	30,724

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See "Natural Gas Contracts with DETM" section of Note 16.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – ExchangeTraded Contracts	$ 4,751	$ 3,330	$ 489	$ -	$ -	$ -	$ 8,570
Prices Provided by Other External Sources – OTC Broker Quotes (a)	9,784	3,876	5,698	-	-	-	19,358
Prices Based on Models and Other Valuation Methods (b)	(5,273)	(1,061)	2,924	6,543	861	1,120	5,114
Total	$ 9,262	$ 6,145	$ 9,111	$ 6,543	$ 861	$ 1,120	$ 33,042

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

We use interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock-in prices on certain transactions 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 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	4,138	-	2,761	6,899
Impact due to Changes in SIA (a)	(337)	-	-	(337)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	631	13	(699)	(55)
Ending Balance in AOCI December 31, 2006	$ 4,040	$ (331)	$ 3,553	$ 7,262

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $4,791 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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$573	$1,451	$500	$271	$583	$968	$461	$166

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

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 $110 million and $111 million at December 31, 2006 and 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
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,006,279	$ 1,922,280	$ 1,752,766
Sales to AEP Affiliates	685,343	681,852	594,357
Other - Affiliated	16,775	15,437	15,013
Other - Nonaffiliated	16,478	14,980	10,589
TOTAL	2,724,875	2,634,549	2,372,725
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	960,119	975,180	819,787
Purchased Electricity for Resale	100,958	77,173	64,229
Purchased Electricity from AEP Affiliates	113,651	116,890	89,355
Other Operation	382,573	340,085	336,330
Maintenance	228,151	207,226	179,290
Depreciation and Amortization	321,954	302,495	286,300
Taxes Other Than Income Taxes	192,178	190,013	177,895
TOTAL	2,299,584	2,209,062	1,953,186
OPERATING INCOME	425,291	425,487	419,539
Other Income (Expense):			
Interest Income	2,363	3,311	3,155
Carrying Costs Income	13,841	48,510	735
Allowance for Equity Funds Used During Construction	2,556	1,441	1,482
Interest Expense	(97,084)	(103,352)	(118,685)
INCOME BEFORE INCOME TAXES	346,967	375,397	306,226
Income Tax Expense	118,324	124,978	96,110
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	228,643	250,419	210,116
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(4,575)	-
NET INCOME	228,643	245,844	210,116
Preferred Stock Dividend Requirements including Other Expense	732	906	733
EARNINGS APPLICABLE TO COMMON STOCK	$ 227,911	$ 244,938	$ 209,383

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

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 321,201	$ 462,484	$ 729,147	$ (48,807)	$ 1,464,025
Common Stock Dividends			(174,114)		(174,114)
Preferred Stock Dividends			(733)		(733)
Capital Stock Gains		1			1
TOTAL					1,289,179
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $723				1,344	1,344
Minimum Pension Liability, Net of Tax of $14,432				(26,801)	(26,801)
NET INCOME			210,116		210,116
TOTAL COMPREHENSIVE INCOME					184,659
DECEMBER 31, 2004	321,201	462,485	764,416	(74,264)	1,473,838
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(732)		(732)
Other		4,152	(174)		3,978
TOTAL					1,447,084
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $262				(486)	(486)
Minimum Pension Liability, Net of Tax of $40,657				75,505	75,505
NET INCOME			245,844		245,844
TOTAL COMPREHENSIVE INCOME					320,863
DECEMBER 31, 2005	321,201	466,637	979,354	755	1,767,947
Capital Contributions from Parent Company		70,000			70,000
Preferred Stock Dividends			(732)		(732)
Gain on Reacquired Preferred Stock		2			2
TOTAL					1,837,217
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,504				6,507	6,507
Minimum Pension Liability, Net of Tax of $110				(204)	(204)
NET INCOME			228,643		228,643
TOTAL COMPREHENSIVE INCOME					234,946
Minimum Pension Liability Elimination, Net of Tax of $110				204	204
SFAS 158 Adoption, Net of Tax of $34,475				(64,025)	(64,025)
DECEMBER 31, 2006	$ 321,201	$ 536,639	$ 1,207,265	$ (56,763)	$ 2,008,342

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,625	$ 1,240
Accounts Receivable:		
Customers	86,116	125,404
Affiliated Companies	108,214	167,579
Accrued Unbilled Revenues	10,106	14,817
Miscellaneous	1,819	15,644
Allowance for Uncollectible Accounts	(824)	(1,517)
Total Accounts Receivable	205,431	321,927
Fuel	120,441	97,600
Materials and Supplies	74,840	60,937
Emission Allowances	10,388	39,251
Risk Management Assets	86,947	115,020
Accrued Tax Benefits	22,909	39,965
Prepayments and Other	18,416	27,439
TOTAL	540,997	703,379
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,413,340	4,278,553
Transmission	1,030,934	1,002,255
Distribution	1,322,103	1,258,518
Other	299,637	293,794
Construction Work in Progress	1,339,631	690,168
Total	8,405,645	7,523,288
Accumulated Depreciation and Amortization	2,836,584	2,738,899
TOTAL - NET	5,569,061	4,784,389
OTHER NONCURRENT ASSETS		
Regulatory Assets	414,180	398,007
Long-term Risk Management Assets	70,092	144,015
Deferred Charges and Other	224,403	300,880
TOTAL	708,675	842,902
TOTAL ASSETS	$ 6,818,733	$ 6,330,670

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 181,281	$ 70,071
Accounts Payable:		
General	250,025	210,752
Affiliated Companies	145,197	147,470
Short-term Debt – Nonaffiliated	1,203	10,366
Long-term Debt Due Within One Year – Nonaffiliated	17,854	12,354
Long-term Debt Due Within One Year – Affiliated	-	200,000
Risk Management Liabilities	73,386	108,797
Customer Deposits	31,465	51,209
Accrued Taxes	165,338	158,774
Accrued Interest	35,497	36,298
Other	123,631	111,480
TOTAL	1,024,877	1,117,571
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,183,887	1,787,316
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	52,929	119,247
Deferred Income Taxes	911,221	987,386
Regulatory Liabilities and Deferred Investment Tax Credits	185,895	168,492
Deferred Credits and Other	219,127	154,770
TOTAL	3,753,059	3,417,211
TOTAL LIABILITIES	4,777,936	4,534,782
Minority Interest	15,825	11,302
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,630	16,639
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	536,639	466,637
Retained Earnings	1,207,265	979,354
Accumulated Other Comprehensive Income (Loss)	(56,763)	755
TOTAL	2,008,342	1,767,947
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,818,733	$ 6,330,670

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

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 228,643	$ 245,844	$ 210,116
Adjustments for Noncash Items:			
Depreciation and Amortization	321,954	302,495	286,300
Deferred Income Taxes	(43,997)	59,593	23,329
Cumulative Effect of Accounting Change, Net of Tax	-	4,575	-
Carrying Costs Income	(13,841)	(48,510)	(735)
Mark-to-Market of Risk Management Contracts	6,545	(2,372)	1,171
Pension Contributions to Qualified Plan Trusts	-	(132,496)	(764)
Change in Other Noncurrent Assets	(735)	5,806	(10,398)
Change in Other Noncurrent Liabilities	10,126	(15,180)	(2,563)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	116,496	(60,627)	(22,640)
Fuel, Materials and Supplies	(36,744)	(32,659)	1,329
Accounts Payable	(14,114)	56,403	31,023
Customer Deposits	(19,744)	28,589	5,312
Accrued Taxes, Net	23,620	(114,217)	100,233
Other Current Assets	39,692	44,516	(71,141)
Other Current Liabilities	8,345	27,045	(4,717)
Net Cash Flows From Operating Activities	626,246	368,805	545,855
INVESTING ACTIVITIES			
Construction Expenditures	(999,603)	(710,536)	(320,215)
Change in Other Cash Deposits, Net	(1,806)	(29)	50,956
Change in Advances to Affiliates, Net	-	125,971	(58,053)
Other	15,314	13,410	2,920
Net Cash Flows Used For Investing Activities	(986,095)	(571,184)	(324,392)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	70,000	-	-
Issuance of Long-term Debt – Nonaffiliated	408,710	545,746	-
Issuance of Long-term Debt – Affiliated	-	-	400,000
Change in Short-term Debt, Net – Nonaffiliated	(9,163)	(13,132)	(2,443)
Change in Advances from Affiliates, Net	111,210	70,071	-
Retirement of Long-term Debt – Nonaffiliated	(12,354)	(365,354)	(431,854)
Retirement of Long-term Debt – Affiliated	(200,000)	-	-
Retirement of Cumulative Preferred Stock	(7)	(5,000)	(2,254)
Principal Payments for Capital Lease Obligations	(7,430)	(7,317)	(8,022)
Dividends Paid on Common Stock	-	(30,000)	(174,114)
Dividends Paid on Cumulative Preferred Stock	(732)	(732)	(733)
Net Cash Flows From (Used For) Financing Activities	360,234	194,282	(219,420)
Net Increase (Decrease) in Cash and Cash Equivalents	385	(8,097)	2,043
Cash and Cash Equivalents at Beginning of Period	1,240	9,337	7,294
Cash and Cash Equivalents at End of Period	$ 1,625	$ 1,240	$ 9,337
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 94,051	$ 102,656	$ 119,562
Net Cash Paid (Received) for Income Taxes	142,895	198,078	(21,600)
Noncash Acquisitions Under Capital Leases	3,288	9,218	14,727
Construction Expenditures Included in Accounts Payable at December 31,	125,962	74,848	35,470

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006. As discussed in Note 17 to the consolidated financial statements, the Company adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Note 9 to the consolidated financial statements, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,441,784	$ 1,304,078	$ 1,047,820	$ 1,107,931	$ 793,282
Operating Income	$ 90,993	$ 118,016	$ 82,806	$ 135,840	$ 101,911
Net Income	$ 36,860	$ 57,893	$ 37,542	$ 53,891	$ 41,060
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 3,186,294	$ 2,994,995	$ 2,875,839	$ 2,818,514	$ 2,771,161
Accumulated Depreciation and Amortization	1,187,107	1,175,858	1,117,535	1,069,417	1,037,222
Net Property, Plant and Equipment	$ 1,999,187	$ 1,819,137	$ 1,758,304	$ 1,749,097	$ 1,733,939
Total Assets	$ 2,579,046	$ 2,355,464	$ 2,066,825	$ 1,976,477	$ 1,987,077
Common Shareholder’s Equity	$ 585,438	$ 548,597	$ 529,256	$ 483,008	$ 399,247
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 5,262	$ 5,262	$ 5,262	$ 5,267	$ 5,267
Trust Preferred Securities	$ -	$ -	$ -	$ -	$ 75,000
Long-term Debt (a)	$ 669,998	$ 571,071	$ 546,092	$ 574,298	$ 545,437
Obligations Under Capital Leases (a)	$ 4,816	$ 2,534	$ 1,284	$ 1,010	$ -

(a) Including portion due within one year.

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

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 520,000 retail customers in our service territory in eastern and southwestern Oklahoma. As a member of the CSW Operating Agreement with SWEPCo, we share in the revenues and expenses of the members' sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Effective May 1, 2006, the FERC approved the removal of TCC and TNC from the CSW Operating Agreement. Under the Texas Restructuring Legislation, TCC and TNC completed the final stage of exiting the generation business and ceased serving retail load. TCC and TNC are no longer involved in the coordinated planning and operation of power supply facilities or share trading and marketing margins, as contemplated by both the CSW Operating Agreement and the SIA. Consequently, our proportionate share of trading and marketing margins increased, although the level of margins depends upon future market conditions. We share these margins with our customers.

Members of the CSW Operating Agreement are compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. We share the revenues and costs of sales to neighboring utilities and power marketers made by AEPSC on our behalf with SWEPCo based upon the relative magnitude of the energy each company provides to make such sales. We share off-system sales margins, if positive on an annual basis, with our customers.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of trading and marketing activities upon the location of such 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 SWEPCo and us. Margins resulting from other transactions are allocated among the AEP East companies, SWEPCo and us in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management expects, due to our generating capacity situation in SPP, a decrease in margins for SWEPCo and us as a result of the SIA change. Our impact will depend upon the level of future trading and marketing margins in SPP and sharing mechanisms with customers for off-system sales margins in Oklahoma. Our results of operations and cash flows for 2006 reflect the new allocation method following the approval of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with SWEPCo. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

Effective January 1, 2007, we locked in our margins on our ERCOT trading and marketing contracts and transferred commodity price risk to AEP Energy Partners, LP (AEPEP), a wholly-owned subsidiary of AEP. This was achieved by a combination of transferring certain existing ERCOT energy marketing contracts to AEPEP and entering into financial and physical purchase and sale agreements with AEPEP. We will not be a party to new contracts in

ERCOT. For future periods as the contracts mature, we will realize the fixed margin on the portfolio of ERCOT contracts as it existed on December 31, 2006 and will not be exposed to commodity price risk and resulting earnings variations for these contracts.

We are jointly and severally liable for activity conducted by AEPSC on our behalf and the behalf of AEP East companies and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to December 31, 2006
Net Income
(in millions)

Year Ended December 31, 2005		$	58
Changes in Gross Margin:			
Retail and Off-system Sales Margins	4		
Transmission Revenues	(3)		
Other	6		
Total Change in Gross Margin			7
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(35)		
Depreciation and Amortization	(1)		
Taxes Other Than Income Taxes	2		
Other Income	(2)		
Interest Expense	(7)		
Total Change in Operating Expenses and Other			(43)
Income Tax Expense			15
Year Ended December 31, 2006		$	37

Net Income decreased $21 million to $37 million in 2006. The key driver of the decrease was a $43 million increase in Operating Expenses and Other, partially offset by a $15 million decrease in Income Tax Expense and a $7 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 chemicals and emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $4 million primarily due to:
  - A $19 million increase in retail base margins due primarily to a $12 million increase in Distribution Vegetation Management (DVM) revenues and a slight increase in KWH sales, partially offset by:
  - A $15 million decrease in off-system sales margins retained. Total off-system sales margins decreased $54 million due to decreased physical sales and a decrease in our allocation of off-system sales margins under the SIA, partially offset by $41 million of the decrease flowing through the fuel adjustment clause and having no impact on Gross Margin. The change in allocation methodology of the SIA occurred on April 1, 2006. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
- Other revenues increased $6 million primarily due to a $3 million increase in rental income for pole attachments and a $2 million increase in revenues for third-party construction projects.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased $35 million due to:
  - A $15 million increase in distribution maintenance primarily related to increased DVM expenses.
  - An $11 million increase in administrative and general expenses, mostly due to increased employee-related expenses.
  - A $5 million increase in expenses related to the factoring of accounts receivable. The $5 million increase in expenses related to the factoring of accounts receivable is primarily due to an increase in accounts receivable factored, an increase in bad debt write-offs and an increase in short-term interest rates.
  - A $4 million increase in forced and scheduled power plant maintenance.
- Interest Expense increased $7 million primarily due to increased borrowings from the Utility Money Pool during the year and the issuance of long-term debt in 2006. The proceeds were primarily used to finance our construction expenditures during the year.

Income Taxes

Income Tax Expense decreased $15 million primarily due to a decrease in pretax book income and the recording of the tax reserve adjustments.

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-

Summary Obligation Information

Our contractual obligations include amounts reported on our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 76.3	$ -	$ -	$ -	$ 76.3
Interest on Fixed Rate Portion of Long-term Debt (b)	35.0	69.0	57.0	305.0	466.0
Fixed Rate Portion of Long-term Debt (c)	-	50.0	225.0	363.0	638.0
Variable Rate Portion of Long-term Debt (d)	-	-	-	34.0	34.0
Capital Lease Obligations (e)	1.7	2.7	0.9	0.1	5.4
Noncancelable Operating Leases (e)	6.8	8.8	6.7	5.8	28.1
Fuel Purchase Contracts (f)	228.7	228.9	136.9	191.9	786.4
Energy and Capacity Purchase Contracts (g)	68.1	151.6	125.7	156.0	501.4
Construction Contracts for Capital Assets (h)	119.3	-	-	0.9	120.2
Total	$ 535.9	$ 511.0	$ 552.2	$ 1,056.7	$ 2,655.8

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 15. Represents principal only excluding interest. Variable rate debt had an interest rate of 3.60% at December 31, 2006.
(e) See Note 14.
(f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

New Generation

In September 2005, we sought proposals for new peaking generation to be online in 2008, and in December 2005 we sought proposals for base load generation to be online in 2011. We received proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In March 2006, we announced plans to add 170 MW of peaking generation to our Riverside Station plant in Jenks, Oklahoma where we will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Also in March 2006, we announced plans to add 170 MW of peaking generation to our Southwestern Station plant in Anadarko, Oklahoma where we will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Combined preliminary cost estimates for these additions are approximately $120 million. In July 2006, we announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E) and Oklahoma Municipal Power Authority (OMPA) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. We will own 50% of the new unit. We, along with OG&E and OMPA, signed an agreement in February 2007 with Red Rock Power Partners to begin the first phase of the project. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion, and the unit is expected to be online no later than the first half of 2012. These new facilities are subject to regulatory approval from the OCC. We expect to begin construction on all of these additions in 2007. Expenditures related to construction of these facilities are expected to total $125 million in 2007.

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” 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 balance sheet as of December 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 Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 100,802	$ -	$ 100,802
Noncurrent Assets	17,066	-	17,066
Total MTM Derivative Contract Assets	117,868	-	117,868
Current Liabilities	(88,469)	-	(88,469)
Noncurrent Liabilities	(11,448)	-	(11,448)
Total MTM Derivative Contract Liabilities	(99,917)	-	(99,917)
Total MTM Derivative Contract Net Assets	$ 17,951	$ -	$ 17,951

MTM Risk Management Contract Net Assets
Year Ended December 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	290
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	(485)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(167)
Changes Due to SIA and CSW Operating Agreement (c)	10,185
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(6,086)
Total MTM Risk Management Contract Net Assets	17,951
Net Cash Flow Hedge Contracts	-
Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 17,951

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ (16,504)	$ 1,569	$ (241)	$ -	$ -	$ -	$ (15,176)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	28,827	4,201	(572)	-	-	-	32,456
Prices Based on Models and Other Valuation Methods (b)	10	(422)	1,082	1	-	-	671
Total	$ 12,333	$ 5,348	$ 269	$ 1	$ -	$ -	$ 17,951

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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

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

We use interest rate derivative transactions to manage interest rate risk related to 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 Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (629)	$ (483)	$ (1,112)
Changes in Fair Value	-	(728)	(728)
Impact Due to Change in SIA (a)	506	-	506
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	123	141	264
Ending Balance in AOCI December 31, 2006	$ -	$ (1,070)	$ (1,070)

(a) See "Allocation Agreement between AEP East companies and AEP West Companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $183 thousand loss.

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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$380	$1,842	$676	$58	$311	$517	$246	$89

The High VaR for the twelve months ended December 31, 2006 occurred in the fourth quarter due to volatility in the ERCOT region.

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 $39 million and $34 million at December 31, 2006 and 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
STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,384,549	$ 1,261,424	$ 1,035,306
Sales to AEP Affiliates	51,993	39,678	10,690
Other	5,242	2,976	1,824
TOTAL	1,441,784	1,304,078	1,047,820
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	703,252	619,657	434,420
Purchased Electricity for Resale	199,094	116,345	79,325
Purchased Electricity from AEP Affiliates	69,406	105,361	104,001
Other Operation	170,201	156,451	155,441
Maintenance	88,676	67,077	63,529
Depreciation and Amortization	87,543	86,762	89,711
Taxes Other Than Income Taxes	32,619	34,409	38,587
TOTAL	1,350,791	1,186,062	965,014
OPERATING INCOME	90,993	118,016	82,806
Other Income (Expense):			
Interest Income	1,917	3,591	166
Allowance for Equity Funds Used During Construction	715	865	336
Interest Expense	(40,778)	(34,094)	(37,957)
INCOME BEFORE INCOME TAXES	52,847	88,378	45,351
Income Tax Expense	15,987	30,485	7,809
NET INCOME	36,860	57,893	37,542
Preferred Stock Dividend Requirements	213	213	213
Gain on Reacquired Preferred Stock	-	-	2
EARNINGS APPLICABLE TO COMMON STOCK	$ 36,647	$ 57,680	$ 37,331

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

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 157,230	$ 230,016	$ 139,604	$ (43,842)	$ 483,008
Common Stock Dividends			(35,000)		(35,000)
Preferred Stock Dividends			(213)		(213)
Gain on Reacquired Preferred Stock			2		2
TOTAL					447,797
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $131				244	244
Minimum Pension Liability, Net of Tax of $23,516				43,673	43,673
NET INCOME			37,542		37,542
TOTAL COMPREHENSIVE INCOME					81,459
DECEMBER 31, 2004	157,230	230,016	141,935	75	529,256
Common Stock Dividends			(37,000)		(37,000)
Preferred Stock Dividends			(213)		(213)
TOTAL					492,043
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $814				(1,512)	(1,512)
Minimum Pension Liability, Net of Tax of $93				173	173
NET INCOME			57,893		57,893
TOTAL COMPREHENSIVE INCOME					56,554
DECEMBER 31, 2005	157,230	230,016	162,615	(1,264)	548,597
Preferred Stock Dividends			(213)		(213)
TOTAL					548,384
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $22				42	42
Minimum Pension Liability, Net of Tax of $14				25	25
NET INCOME			36,860		36,860
TOTAL COMPREHENSIVE INCOME					36,927
Minimum Pension Liability Elimination, Net of Tax of $68				127	127
DECEMBER 31, 2006	$ 157,230	$ 230,016	$ 199,262	$ (1,070)	$ 585,438

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,651	$ 1,520
Accounts Receivable:		
Customers	70,319	37,740
Affiliated Companies	73,318	73,321
Miscellaneous	10,270	10,501
Allowance for Uncollectible Accounts	(5)	(240)
Total Accounts Receivable	153,902	121,322
Fuel	20,082	16,431
Materials and Supplies	48,375	38,545
Risk Management Assets	100,802	40,383
Accrued Tax Benefits	4,679	11,972
Regulatory Asset for Under-Recovered Fuel Costs	7,557	108,732
Margin Deposits	35,270	10,051
Prepayments and Other	5,732	4,236
TOTAL	378,050	353,192
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,091,910	1,072,928
Transmission	503,638	479,272
Distribution	1,215,236	1,140,535
Other	234,227	211,805
Construction Work in Progress	141,283	90,455
Total	3,186,294	2,994,995
Accumulated Depreciation and Amortization	1,187,107	1,175,858
TOTAL - NET	1,999,187	1,819,137
OTHER NONCURRENT ASSETS		
Regulatory Assets	142,905	50,723
Long-term Risk Management Assets	17,066	33,566
Employee Benefits and Pension Assets	30,161	82,559
Deferred Charges and Other	11,677	16,287
TOTAL	201,809	183,135
TOTAL ASSETS	$ 2,579,046	$ 2,355,464

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 76,323	$ 75,883
Accounts Payable:		
General	165,618	130,627
Affiliated Companies	65,134	89,786
Long-term Debt Due Within One Year – Affiliated	-	50,000
Risk Management Liabilities	88,469	38,243
Customer Deposits	51,335	53,844
Accrued Taxes	19,984	22,420
Other	58,651	51,548
TOTAL	525,514	512,351
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	669,998	521,071
Long-term Risk Management Liabilities	11,448	22,582
Deferred Income Taxes	414,197	436,382
Regulatory Liabilities and Deferred Investment Tax Credits	315,584	284,640
Deferred Credits and Other	51,605	24,579
TOTAL	1,462,832	1,289,254
TOTAL LIABILITIES	1,988,346	1,801,605
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 6)		
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	199,262	162,615
Accumulated Other Comprehensive Income (Loss)	(1,070)	(1,264)
TOTAL	585,438	548,597
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,579,046	$ 2,355,464

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 36,860	$ 57,893	$ 37,542
Adjustments for Noncash Items:			
Depreciation and Amortization	87,543	86,762	89,711
Deferred Income Taxes	(23,672)	46,342	22,034
Mark-to-Market of Risk Management Contracts	(3,737)	557	(714)
Pension Contributions to Qualified Plan Trusts	-	(286)	(48,701)
Fuel Over/Under Recovery, Net	101,175	(108,366)	23,804
Change in Other Noncurrent Assets	23,117	(30,602)	(24,711)
Change in Other Noncurrent Liabilities	(17,920)	8,603	24,848
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(32,580)	(33,924)	(37,826)
Fuel, Materials and Supplies	(13,481)	(5,223)	6,731
Margin Deposits	(25,219)	(7,170)	1,470
Accounts Payable	3,906	86,314	23,535
Customer Deposits	(2,509)	20,087	7,210
Accrued Taxes, Net	4,857	(8,387)	(8,322)
Other Current Assets	(1,502)	(911)	(715)
Other Current Liabilities	5,529	16,511	(4,353)
Net Cash Flows From Operating Activities	142,367	128,200	111,543
INVESTING ACTIVITIES			
Construction Expenditures	(240,238)	(134,358)	(82,618)
Change in Other Cash Deposits, Net	6	(6)	10,258
Proceeds from Sales of Assets	226	-	458
Net Cash Flows Used For Investing Activities	(240,006)	(134,364)	(71,902)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	148,695	74,405	82,255
Issuance of Long-term Debt – Affiliated	-	-	50,000
Change in Advances from Affiliates, Net	440	20,881	22,138
Retirement of Long-term Debt – Nonaffiliated	-	(50,000)	(162,020)
Retirement of Long-term Debt – Affiliated	(50,000)	-	-
Gain on Reacquired Preferred Stock	-	-	(2)
Principal Payments for Capital Lease Obligations	(1,152)	(668)	(520)
Dividends Paid on Common Stock	-	(37,000)	(35,000)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows From (Used For) Financing Activities	97,770	7,405	(43,362)
Net Increase (Decrease) in Cash and Cash Equivalents	131	1,241	(3,721)
Cash and Cash Equivalents at Beginning of Period	1,520	279	4,000
Cash and Cash Equivalents at End of Period	$ 1,651	$ 1,520	$ 279
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 32,652	$ 29,607	$ 32,961
Net Cash Paid (Received) for Income Taxes	29,879	(5,244)	2,387
Noncash Acquisitions Under Capital Leases	3,435	1,918	796
Construction Expenditures Included in Accounts Payable at December 31,	14,928	8,495	2,477

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

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2006 and 2005, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006, and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,431,839	$ 1,405,379	$ 1,091,072	$ 1,148,812	$ 1,085,100
Operating Income	$ 189,618	$ 160,537	$ 179,239	$ 203,778	$ 174,711
Income Before Cumulative Effect of Accounting Changes	$ 91,723	$ 75,190	$ 89,457	$ 89,624	$ 82,992
Cumulative Effect of Accounting Changes, Net of Tax	-	(1,252)	-	8,517	-
Net Income	$ 91,723	$ 73,938	$ 89,457	$ 98,141	$ 82,992
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 4,328,247	$ 4,006,639	$ 3,892,508	$ 3,804,600	$ 3,600,407
Accumulated Depreciation and Amortization	1,834,145	1,776,216	1,710,850	1,619,178	1,477,904
Net Property, Plant and Equipment	$ 2,494,102	$ 2,230,423	$ 2,181,658	$ 2,185,422	$ 2,122,503
Total Assets	$ 3,190,968	$ 2,797,347	$ 2,646,849	$ 2,581,727	$ 2,429,366
Common Shareholder's Equity	$ 821,202	$ 782,378	$ 768,618	$ 696,660	$ 661,769
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 4,697	$ 4,700	$ 4,700	$ 4,700	$ 4,701
Trust Preferred Securities (a)	$ -	$ -	$ -	$ -	$ 110,000
Long-term Debt (b)	$ 729,006	$ 744,641	$ 805,369	$ 884,308	$ 693,448
Obligations Under Capital Leases (b)	$ 84,715 (c)	$ 42,545	$ 34,546	$ 21,542	$ -

(a) See “Trust Preferred Securities” section of Note 15.
(b) Including portion due within one year.
(c) Increased primarily due to new leases for coal handling equipment.

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

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 456,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. We consolidate Southwest Arkansas Utilities Corporation and Dolet Hills Lignite Company, LLC, our wholly-owned subsidiaries. We also consolidate Sabine Mining Company, a variable interest entity. As a member of the CSW Operating Agreement with PSO, we share in the revenues and expenses of the members' sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and electric cooperatives.

Effective May 1, 2006, the FERC approved the removal of TCC and TNC from the CSW Operating Agreement. Under the Texas Restructuring Legislation, TCC and TNC completed the final stage of exiting the generation business and ceased serving retail load. TCC and TNC are no longer involved in the coordinated planning and operation of power supply facilities or share trading and marketing margins, as contemplated by both the CSW Operating Agreement and the SIA. Consequently, our proportionate share of trading and marketing margins increased, although the level of margins depends upon future market conditions. We share these margins with our customers.

Members of the CSW Operating Agreement are compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. We share the revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on our behalf with PSO based upon the relative magnitude of the energy each company provides to make such sales. We share these margins with our customers.

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of trading and marketing activities upon the location of such 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 us. Margins resulting from other transactions are allocated among the AEP East companies, PSO and us in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. We expect, due to our generating capacity situation in SPP, a decrease in margins for PSO and us as a result of the SIA change. Our impact will depend upon the level of future trading and marketing margins in SPP and sharing mechanisms with customers for off-system sales margins in Arkansas, Louisiana and Texas. Our results of operations and cash flows for 2006 reflect the new allocation method following the approval of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with PSO. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

Effective January 1, 2007, we locked in our margins on our ERCOT trading and marketing contracts and transferred commodity price risk to AEP Energy Partners, LP (AEPEP), a wholly-owned subsidiary of AEP. This was achieved by a combination of transferring certain existing ERCOT energy marketing contracts to AEPEP and entering into financial and physical purchase and sale agreements with AEPEP. We will not be a party to new contracts in ERCOT. For future periods as the contracts mature, we will realize the fixed margin on the portfolio of ERCOT contracts as it existed on December 31, 2006 and will not be exposed to commodity price risk and resulting earnings variations for these contracts.

We are jointly and severally liable for activity conducted by AEPSC on our behalf and the behalf of AEP East companies and PSO related to power purchase and sale activity pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2005		$ 75
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	14	
Transmission Revenues	2	
Other	22	
Total Change in Gross Margin		38
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(11)	
Taxes Other Than Income Taxes	4	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(12)
Income Tax Expense		(9)
Year Ended December 31, 2006		$ 92

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

Income Before Cumulative Effect of Accounting Change increased $17 million in 2006. The key driver of the increase was a $38 million increase in Gross Margin, partially offset by a $12 million increase in Operating Expenses and Other and a $9 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 $14 million primarily due to:
  - A $22 million increase in retail margins primarily due to favorable prices, increased usage and new contracts related to wholesale sales and increased ancillary services, partially offset by:
  - An $8 million decrease in off-system sales margins retained. Total off-system margins decreased $51 million due to decreased physical sales and a decrease in our allocation of off-system sales margins under the SIA, partially offset by $38 million of the decrease flowing through the fuel adjustment clause, and having no impact on Gross Margin, and a $6 million increase in other off-system sales not flowed through the fuel adjustment clause. The change in allocation methodology of the SIA occurred on April 1, 2006. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Agreement” section of Note 4.
- Other revenues increased $22 million primarily due to gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $11 million primarily due to an increase in employee-related expenses.
- Taxes Other Than Income Taxes decreased $4 million primarily due to an adjustment to the provision for state sales and use tax in 2006.
- Interest Expense increased $5 million primarily due to increased Utility Money Pool borrowings in 2006.

Income Taxes

Income Tax Expense increased $9 million primarily due to an increase in pretax book income and state income taxes, offset in part, by the recording of the tax return adjustments.

<u>2005 Compared to 2004</u>

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 89
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	23	
Transmission Revenues	4	
Other	8	
Total Change in Gross Margin		35
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(49)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(3)	
Other Income	1	
Interest Expense	4	
Total Change in Operating Expenses and Other		(49)
Year Ended December 31, 2005		$ 75

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

Income Before Cumulative Effect of Accounting Change decreased $14 million to $75 million in 2005. The key driver of the decrease was a $49 million increase in Other Operation and Maintenance expenses partially offset by a $35 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 chemicals and emissions allowances, and purchased power were as follows:

- Retail and Off-system Sales Margins increased $23 million primarily due to higher wholesale volumes and higher retail sales volumes resulting from a 10% increase in degree days. This was offset by a one-time $9 million refund received in 2004 for purchased capacity. Capacity-related transactions are excluded from fuel adjustment clauses. Therefore, these transactions impact gross margin.
- Transmission Revenues increased $4 million primarily due to higher rates within SPP.
- Other revenues increased $8 million primarily due to a $4 million increase in pole attachment billings and other miscellaneous revenues.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $49 million. This was primarily due to:
  - A $27 million increase in power plant operation and maintenance during extended planned power plant outages,
  - A $14 million increase in distribution expense, comprised primarily of a $10 million increase in tree trimming and right-of-way clearing and $3 million of storm damage related to hurricanes,
  - A $6 million increase in customer-related expense due to increased collection activities as well as increased factoring expense resulting from higher interest rates and higher volumes of receivables factored.
- Taxes Other Than Income Taxes increased $3 million primarily due to higher gross receipts and payroll-related taxes.
- Interest Expense decreased $4 million primarily due to decreased long-term debt and decreased interest expense related to fuel recovery.

Income Taxes

Income Tax expense remained relatively flat in 2005.

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 2006, 2005 and 2004 were as follows:

	2006	**2005**	**2004**
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 3,049	$ 3,715	$ 6,215
Cash Flows From (Used For):			
Operating Activities	210,136	208,153	209,107
Investing Activities	(323,193)	(115,073)	(65,525)
Financing Activities	112,626	(93,746)	(146,082)
Net Decrease in Cash and Cash Equivalents	(431)	(666)	(2,500)
Cash and Cash Equivalents at End of Period	$ 2,618	$ 3,049	$ 3,715

Operating Activities

Net Cash Flows From Operating Activities were $210 million in 2006. We produced Net Income of $92 million during the period and a noncash expense item of $132 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. Our $74 million inflow related to Fuel Over/Under Recovery, Net was primarily due to the new fuel surcharges effective December 2005 in our Arkansas service territory and in January 2006 in our Texas service territory. The $67 million inflow from Accounts Payable was the result of higher energy purchases. The $52 million outflow from Accounts Receivable, Net was primarily due to an increase in our proportionate share of trading and marketing Accounts Receivable as a result of changes in the CSW Operating Agreement and the SIA. The $40 million outflow from Fuel, Materials and Supplies was the result of increased fuel purchases. The $28 million outflow for Margin Deposits was due to increased trading-related deposits resulting from the amended SIA.

Our Net Cash Flows From Operating Activities were $208 million in 2005. We produced Net Income of $74 million during the period and a noncash expense item of $132 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 are Accounts Receivable, Accounts Payable, and Customer Deposits, all of which were driven by higher fuel-related costs. Our cash flow related to Fuel Over/Under Recovery, Net was also adversely affected by rising fuel costs. Accounts Receivable increased $28 million due to higher affiliated energy sales. Accounts Payable increased $46 million primarily due to higher energy and fuel-related purchases as well as increased vendor-related payables.

Our Net Cash Flows From Operating Activities were $209 million in 2004. We produced Net Income of $89 million during the period and a noncash expense item of $129 million for Depreciation and Amortization. Pension Contributions to Qualified Plan Trusts were $46 million. 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 being Accrued Taxes, Fuel, Materials and Supplies, and Accounts Receivable. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Federal income tax payments were made in 2005. The decrease in Fuel and Materials and Supplies was primarily due to lower fuel purchases. Accounts Receivable increased due to higher affiliated energy sales.

Investing Activities

Cash Flows Used For Investing Activities during 2006, 2005 and 2004 were $323 million, $115 million and $66 million, respectively. The cash flows during 2006 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability as well as projects related to new generation facilities. The cash flows during 2005 and 2004 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability offset by Advances to Affiliates.

Financing Activities

Cash Flows From Financing Activities were $113 million during 2006. We had a net increase of $161 million in borrowings from the Utility Money Pool during the fourth quarter. We refinanced (retired and issued) $82 million of Pollution Control Bonds and retired $15 million of long-term debt. We had a net increase in short-term debt of $16 million. In addition, we paid $40 million in common stock dividends.

Cash Flows Used For Financing Activities were $94 million during 2005. During the year, we issued $150 million of Senior Unsecured Notes. Proceeds were used to fund the July 2005 maturity of $200 million of Senior Unsecured Notes. In addition, we had a net increase of $28 million in borrowings from the Utility Money Pool. We paid $55 million in common stock dividends in 2005.

Cash Flows Used For Financing Activities were $146 million during 2004. We retired $120 million of First Mortgage Bonds. Pollution Control Bonds were retired totaling $41 million. During the third quarter of 2004, we issued a Note Payable to AEP for $50 million. We also paid $60 million in common stock dividends in 2004.

Summary Obligation Information

Our contractual obligations include amounts reported on our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 189.0	$ -	$ -	$ -	$ 189.0
Short-term Debt (b)	17.1	-	-	-	17.1
Interest on Fixed Rate Portion of Long-term Debt (c)	27.0	34.0	30.0	48.0	139.0
Fixed Rate Portion of Long-term Debt (d)	102.0	10.0	56.0	383.0	551.0
Variable Rate Portion of Long-term Debt (e)	-	-	41.0	135.0	176.0
Capital Lease Obligations (f)	13.5	27.5	17.5	61.2	119.7
Noncancelable Operating Leases (f)	7.4	12.3	6.7	6.1	32.5
Fuel Purchase Contracts (g)	347.3	692.6	555.6	2,118.7	3,714.2
Energy and Capacity Purchase Contracts (h)	86.4	184.7	156.6	246.8	674.5
Construction Contracts for Capital Assets (i)	224.5	220.0	-	1.1	445.6
Total	$ 1,014.2	$ 1,181.1	$ 863.4	$ 2,999.9	$ 6,058.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Represents principal only excluding interest.
(c) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(d) See Note 15. Represents principal only excluding interest.
(e) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates of 3.60% and 5.94% at December 31, 2006.
(f) See Note 14.
(g) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(h) Represents contractual cash flows of energy and capacity purchase contracts.
(i) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2006 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a)	$ 4	$ -	$ -	$ -	$ 4
Guarantees of the Performance of Outside Parties (b)	-	-	-	85	85
Total	$ 4	$ -	$ -	$ 85	$ 89

(a) We have issued standby letters of credit to third parties. These letters of credit cover insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $4 million maturing in June 2007. There is no recourse to third parties in the event these letters of credit are drawn. See “Letters of Credit” section of Note 6.
(b) See “SWEPCo” section of Note 6.

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. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

New Generation

In December 2005, we sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, we announced plans to construct new generation to satisfy the demands of our customers. We will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at our existing Arsenal Hill Power Plant in Shreveport, Louisiana. We also plan to build a new 600 MW base load coal plant, of which SWEPCo's investment will be 73%, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of our customers. Preliminary cost estimates for our share of the new facilities are approximately $1.4 billion (this total excludes the related transmission investment and AFUDC). These new facilities are subject to regulatory approvals from our three state commissions. The peaking generation facility at Tontitown, Arkansas has been approved by all three commissions and Units 3 and 4 are projected to be online in July 2007 and the remaining two units by 2008. Construction is expected to begin in 2007 on the intermediate and base load facilities upon approval from the state regulatory commissions. Expenditures related to construction of these facilities are expected to total $349 million in 2007.

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" 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 balance sheet as of December 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 Consolidated Balance Sheet As of December 31, 2006 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 119,560	$ 476	$ 120,036
Noncurrent Assets	20,502	29	20,531
Total MTM Derivative Contract Assets	140,062	505	140,567
Current Liabilities	(105,829)	(3,749)	(109,578)
Noncurrent Liabilities	(14,067)	(16)	(14,083)
Total MTM Derivative Contract Liabilities	(119,896)	(3,765)	(123,661)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,166	$ (3,260)	$ 16,906

MTM Risk Management Contract Net Assets Year Ended December 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	(332)
Fair Value of New Contracts at Inception When Entered During the Period (a)	52
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(611)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	139
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(2,003)
Changes Due to SIA and CSW Operating Agreement (c)	11,900
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(5,366)
Total MTM Risk Management Contract Net Assets	20,166
Net Cash Flow Hedge Contracts	(3,260)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 16,906

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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 to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ (19,349)	$ 1,909	$ (283)	$ -	$ -	$ -	$ (17,723)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	33,639	4,942	(673)	-	-	-	37,908
Prices Based on Models and Other Valuation Methods (b)	(559)	(736)	1,274	2	-	-	(19)
Total	$ 13,731	$ 6,115	$ 318	$ 2	$ -	$ -	$ 20,166

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the 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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

We use interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We use forward contracts and collars as cash flow hedges to lock-in prices on certain transactions 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 Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to December 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
Year Ended December 31, 2006
(in thousands)

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2005	$ (736)	$ (5,116)	$ -	$ (5,852)
Changes in Fair Value	-	(1,858)	25	(1,833)
Impact due to Change in SIA (a)	592	-	-	592
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	144	539	-	683
Ending Balance in AOCI December 31, 2006	$ -	$ (6,435)	$ 25	$ (6,410)

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $755 thousand loss.

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 December 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 years ended:

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$447	$2,171	$794	$68	$363	$604	$287	$104

The High VaR for the twelve months ended December 31, 2006 occurred in the fourth quarter due to volatility in the ERCOT region.

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 $25 million and $31 million at December 31, 2006 and 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
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,386,653	$ 1,338,882	$ 1,018,209
Sales to AEP Affiliates	42,445	65,408	71,190
Other	2,741	1,089	1,673
TOTAL	1,431,839	1,405,379	1,091,072
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	471,418	527,525	388,380
Purchased Electricity for Resale	175,124	133,403	35,521
Purchased Electricity from AEP Affiliates	74,458	70,911	29,054
Other Operation	224,750	213,629	191,898
Maintenance	100,962	101,049	74,091
Depreciation and Amortization	132,261	131,620	129,329
Taxes Other Than Income Taxes	63,248	66,705	63,560
TOTAL	1,242,221	1,244,842	911,833
OPERATING INCOME	189,618	160,537	179,239
Other Income (Expense):			
Interest Income	2,582	1,499	1,658
Allowance for Equity Funds Used During Construction	1,302	2,394	781
Interest Expense	(55,213)	(50,089)	(54,261)
INCOME BEFORE INCOME TAXES, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	138,289	114,341	127,417
Income Tax Expense	43,697	34,922	34,727
Minority Interest Expense	2,868	4,226	3,230
Equity Earnings of Unconsolidated Subsidiaries	(1)	(3)	(3)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	91,723	75,190	89,457
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	(1,252)	-
NET INCOME	91,723	73,938	89,457
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$ 91,494	$ 73,709	$ 89,228

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 135,660	$ 245,003	$ 359,907	$ (43,910)	$ 696,660
Common Stock Dividends			(60,000)		(60,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					636,431
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $541				(1,004)	(1,004)
Minimum Pension Liability, Net of Tax of $23,550				43,734	43,734
NET INCOME			89,457		89,457
TOTAL COMPREHENSIVE INCOME					132,187
DECEMBER 31, 2004	135,660	245,003	389,135	(1,180)	768,618
Common Stock Dividends			(55,000)		(55,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					713,389
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,709				(5,032)	(5,032)
Minimum Pension Liability, Net of Tax of $44				83	83
NET INCOME			73,938		73,938
TOTAL COMPREHENSIVE INCOME					68,989
DECEMBER 31, 2005	135,660	245,003	407,844	(6,129)	782,378
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					742,149
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $515				(558)	(558)
Minimum Pension Liability, Net of Tax of $35				65	65
NET INCOME			91,723		91,723
TOTAL COMPREHENSIVE INCOME					91,230
Minimum Pension Liability Elimination, Net of Tax of $114				212	212
SFAS 158 Adoption, Net of Tax of $6,671				(12,389)	(12,389)
DECEMBER 31, 2006	$ 135,660	$ 245,003	$ 459,338	$ (18,799)	$ 821,202

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,618	$ 3,049
Accounts Receivable:		
Customers	88,245	47,515
Affiliated Companies	59,679	49,226
Miscellaneous	8,595	7,984
Allowance for Uncollectible Accounts	(130)	(548)
Total Accounts Receivable	156,389	104,177
Fuel	69,426	40,333
Materials and Supplies	46,001	34,821
Risk Management Assets	120,036	47,319
Regulatory Asset for Under-Recovered Fuel Costs	-	51,387
Margin Deposits	41,579	13,740
Prepayments and Other	18,256	20,270
TOTAL	454,305	315,096
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,576,200	1,513,436
Transmission	668,008	645,297
Distribution	1,228,948	1,153,026
Other	595,429	590,705
Construction Work in Progress	259,662	104,175
Total	4,328,247	4,006,639
Accumulated Depreciation and Amortization	1,834,145	1,776,216
TOTAL - NET	2,494,102	2,230,423
OTHER NONCURRENT ASSETS		
Regulatory Assets	156,420	81,776
Long-term Risk Management Assets	20,531	39,796
Employee Benefits and Pension Assets	26,029	83,330
Deferred Charges and Other	39,581	46,926
TOTAL	242,561	251,828
TOTAL ASSETS	$ 3,190,968	$ 2,797,347

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2006 and 2005

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 188,965	$ 28,210
Accounts Payable:		
General	140,424	71,138
Affiliated Companies	68,680	53,019
Short-term Debt – Nonaffiliated	17,143	1,394
Long-term Debt Due Within One Year – Nonaffiliated	102,312	15,755
Risk Management Liabilities	109,578	45,098
Customer Deposits	48,277	50,848
Accrued Taxes	31,591	42,799
Regulatory Liability for Over-Recovered Fuel Costs	26,012	3,181
Other	85,086	79,518
TOTAL	818,068	390,960
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	576,694	678,886
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	14,083	27,083
Deferred Income Taxes	374,548	409,513
Regulatory Liabilities and Deferred Investment Tax Credits	346,774	320,066
Deferred Credits and Other	183,087	131,477
TOTAL	1,545,186	1,617,025
TOTAL LIABILITIES	2,363,254	2,007,985
Minority Interest	1,815	2,284
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,700
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $18 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	459,338	407,844
Accumulated Other Comprehensive Income (Loss)	(18,799)	(6,129)
TOTAL	821,202	782,378
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,190,968	$ 2,797,347

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 91,723	$ 73,938	$ 89,457
Adjustments for Noncash Items:			
Depreciation and Amortization	132,261	131,620	129,329
Deferred Income Taxes	(23,667)	(4,942)	12,782
Cumulative Effect of Accounting Change, Net of Tax	-	1,252	-
Mark-to-Market of Risk Management Contracts	(3,779)	1,140	(921)
Pension Contributions to Qualified Plan Trusts	-	(3,450)	(45,688)
Change in Other Noncurrent Assets	29,902	(27,432)	(20,447)
Change in Other Noncurrent Liabilities	(30,580)	25,625	36,224
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(52,212)	(27,835)	(19,832)
Fuel, Materials and Supplies	(40,273)	6,690	15,824
Margin Deposits	(27,839)	(10,321)	1,703
Accounts Payable	67,452	45,742	(2,267)
Customer Deposits	(2,571)	20,298	6,290
Accrued Taxes, Net	(11,208)	(2,675)	16,783
Fuel Over/Under Recovery, Net	74,218	(53,410)	12,420
Other Current Assets	2,134	2,014	(845)
Other Current Liabilities	4,575	29,899	(21,705)
Net Cash Flows From Operating Activities	210,136	208,153	209,107
INVESTING ACTIVITIES			
Construction Expenditures	(323,332)	(157,595)	(98,954)
Change in Other Cash Deposits, Net	(120)	3,308	624
Change in Advances to Affiliates, Net	-	39,106	27,370
Proceeds from Sales of Assets	259	108	5,435
Net Cash Flows Used For Investing Activities	(323,193)	(115,073)	(65,525)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	80,593	154,574	91,999
Issuance of Long-term Debt – Affiliated	-	-	50,000
Change in Short-term Debt, Net – Nonaffiliated	15,749	-	-
Change in Advances from Affiliates, Net	160,755	28,210	-
Retirement of Long-term Debt – Nonaffiliated	(97,455)	(215,101)	(224,309)
Retirement of Cumulative Preferred Stock	(3)	-	-
Principal Payments for Capital Lease Obligations	(6,784)	(6,200)	(3,543)
Dividends Paid on Common Stock	(40,000)	(55,000)	(60,000)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows From (Used For) Financing Activities	112,626	(93,746)	(146,082)
Net Decrease in Cash and Cash Equivalents	(431)	(666)	(2,500)
Cash and Cash Equivalents at Beginning of Period	3,049	3,715	6,215
Cash and Cash Equivalents at End of Period	$ 2,618	$ 3,049	$ 3,715
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 47,610	$ 43,673	$ 49,739
Net Cash Paid for Income Taxes	82,267	52,756	11,326
Noncash Acquisitions Under Capital Leases	48,777	9,629	19,687
Construction Expenditures Included in Accounts Payable at December 31,	27,716	10,221	5,475

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the consolidated financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006 and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Change	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Commitments, Guarantees and Contingencies	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.	Acquisitions, Dispositions, Asset Impairments and Assets Held for Sale	AEGCo, APCo, CSPCo, TCC
9.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Nuclear	I&M, TCC
11.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
15.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Property, Plant and Equipment	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of AEP's ten Registrant Subsidiaries is the generation, transmission and distribution of electric power. TCC and TNC are completing the final stage of exiting the generation business. AEGCo is a regulated electricity generation business whose function is to provide power to I&M and KPCo. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, Registrant Subsidiaries engage in wholesale electricity marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP, AEPSC and its other subsidiaries are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA). AEP's public utility subsidiaries are regulated by the FERC and state regulatory commissions in the eleven state operating territories. The state regulatory commissions with jurisdiction approve the rates charged and regulate the services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services. The FERC also regulates certain, mostly affiliated, transactions under the 2005 PUHCA.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrant Subsidiaries' wholesale power transactions are generally market-based and are not cost-based regulated unless the Registrant Subsidiaries negotiate and file a cost-based contract with the FERC or the FERC determines that the Registrant Subsidiaries have "market power" in the region in which the transaction is taking place. The Registrant Subsidiaries have wholesale power supply contracts with various municipalities and cooperatives that are FERC regulated, cost-based contracts and wholesale power transactions in the SPP region are all cost-based due to having market power in the SPP region as determined by the FERC. As of December 31, 2006, only SWEPCo, PSO and TNC operate in the SPP region.

The FERC also regulates, on a cost basis, the Registrant Subsidiaries' wholesale transmission service and rates except in Texas. The FERC has claimed jurisdiction over retail transmission rates when the retail rates are unbundled in connection with restructuring. In Ohio, CSPCo's and OPCo's rates are unbundled, therefore their retail transmission rates are based on FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although the retail rates are unbundled in Virginia and Texas, retail transmission rates are still regulated on a cost basis by the state regulatory commissions.

In addition, FERC regulates the East and West Power Pools, East Transmission Equalization Agreement, System Interim Allowance Agreement, and SIA, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to the agreements.

The state regulatory commissions regulate all of the retail public utility operations (generation, transmission and distribution operations) and rates except in states that have enacted restructuring legislation where only transmission and distribution rates are regulated on a cost-basis and unbundled by function. The retail generation/power supply operations and rates are cost-based regulated by the state regulatory commissions except for CSPCo and OPCo in Ohio and APCo in Virginia, which are in transition to market pricing under state restructuring legislation. However, Virginia legislature adopted amendments to its electric restructuring law. If approved, Virginia would return to a form of cost-based regulation. AEP has no Texas jurisdictional retail generation/power supply operations in Texas other than a minor generational supply operation through a commercial and industrial customer REP. See Note 4 for further details of such legislation and its effects on AEP in Ohio, Texas, Virginia and Michigan.

In 2004 and 2005, the Registrant Subsidiaries were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated predominantly at cost. Jurisdiction over holding company-related activities has been transferred to the FERC. Regulation and required reporting under the 2005 PUHCA have been reduced compared to the 1935 PUHCA. However, the FERC has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, inter-company transactions, accounting and AEPSC inter-company service billings which are generally at cost. The inter-company sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA. The state regulatory commissions in Virginia and West Virginia also regulate certain inter-company transactions under their affiliates statutes.

Both FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCo, SWEPCo, TCC and TNC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. OPCo and SWEPCo also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see "SWEPCo" section of Note 6 and "Gavin Scrubber Financing Arrangement" section of Note 14). CSPCo, OPCo, PSO, SWEPCo, TCC and TNC also have generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the financial statements and the assets and liabilities are reflected in the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries' financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to commencement of legislatively required transitions to customer choice and market-based rates, the following Registrant Subsidiaries discontinued the application of SFAS 71, regulatory accounting, for the generation portion of their business as follows: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000, in Texas for TCC, TNC and the Texas portion of SWEPCo in September 1999. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of stranded regulatory assets and stranded plants costs if they are not recoverable in regulated rates. Such impairments arising from the discontinuance of SFAS 71 are classified as an extraordinary item. TCC recorded extraordinary impairment losses related to its regulatory assets and plant costs in 2004 and 2005 resulting from the discontinuance of cost-based regulation of its generation businesses without full recovery of the resultant stranded costs.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the nonregulated operations and investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations including domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt and to secure the payments of customers.

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales or delivery when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and certain subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 15).

Concentrations of Credit Risk and Significant Customers

TNC and TCC have significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable – Customers as of December 31:

	2006	2005	2004
		(in percentage)	
TCC –ERCOT and Centrica			
Percentage of Operating Revenues	29	29	72
Percentage of Accounts Receivable - Customers	7	7	54
TNC –ERCOT, Centrica and City of College Station (2006 only)			
Percentage of Operating Revenues	50	27	57
Percentage of Accounts Receivable - Customers	38	12	59

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. Management believes adequate provision for credit loss has been made in the accompanying registrant financial statements.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit fuel cost calculations. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). For TCC & TNC, their deferred fuel balances were included in their True-up Proceedings (see Note 4). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, Michigan for I&M, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia and West Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky, West Virginia (beginning July 1, 2006) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana and prior to July 1, 2006 in West Virginia) where fuel clauses have been capped, frozen or suspended for a period of years, fuel costs impact earnings. The Indiana fuel clause suspension ends June 30, 2007. In West Virginia, deferred fuel accounting for over- or under-recovery began July 1, 2006.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains and losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

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

Traditional Electricity Supply and Delivery Activities

Registrant Subsidiaries recognize revenues from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. Registrant Subsidiaries recognize the revenues in the financial statements upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. In general, Registrant Subsidiaries record expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, AEP's west zone is short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEP's west zone where the AEP West companies are short capacity, prior to settlement, they recognize as Revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period. If the contract results in the physical delivery of power, the Registrant Subsidiaries reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy for Resale. If the contract does not physically deliver, the Registrant Subsidiaries reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues in the financial statements on a net basis (see "Derivatives and Hedging" section of Note 12).

Energy Marketing and Risk Management Activities

All of the Registrant Subsidiaries except AEGCo engage in wholesale electricity, coal and emission allowances marketing and risk management activities focused on wholesale markets where Registrant Subsidiaries own assets. Registrant Subsidiaries' activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps.

Registrant Subsidiaries recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. Registrant Subsidiaries use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow or fair value hedge relationship, or as a normal purchase or sale. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in the financial statements on a net basis. In jurisdictions subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions, a future cash flow (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the financial statements in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and, depending upon the specific nature of the risk being hedged, subsequently reclassified into Revenues or fuel expenses in the financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the financial statements immediately, except in those jurisdictions subject to cost-based regulation. In those regulated jurisdictions the Registrant Subsidiaries defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" section of Note 12).

Construction Projects for Outside Parties

TCC and TNC engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred. TCC and TNC include such revenue and related expenses in Other Revenue and Other Operation Expenses, respectively, in the financial statements. TCC and TNC include contractually billable expenses not yet billed in Current Assets in the financial statements.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

Registrant Subsidiaries expense maintenance costs as incurred. If it becomes probable that Registrant Subsidiaries will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

Income Taxes and Investment Tax Credits

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

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

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

Excise Taxes

Registrant Subsidiaries, as agents for some state and local governments, collect from customers certain excise taxes levied by those state or local governments on customers. Registrant Subsidiaries do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The amortization expense is included in Interest Expense.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain Registrant Subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

SWEPCo is the only Registrant Subsidiary with an intangible asset with a finite life. SWEPCo amortizes the asset over its estimated life to its residual value (see Note 3). The Registrant Subsidiaries have no recorded goodwill or intangible assets with indefinite lives as of December 31, 2006 and 2005.

Emission Allowances

The Registrant Subsidiaries, except AEGCo, record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. They follow the inventory model for all allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets-Deferred Charges and Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Current Assets-Prepayments and Other for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries revenue optimization strategy for their operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of the applicable company or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction, which are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel in Spent Nuclear Fuel and Decommissioning Trusts on its Consolidated Balance Sheet. I&M records these securities at market value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Upon the issuance of FSP 115-1 and 124-1 "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," I&M considers all nuclear decommissioning trust fund and spent nuclear fuel trust fund investments in unrealized loss positions to be other-than-temporary impairments as we do not make specific investment decisions regarding assets held in trusts. Thus, effective in 2006, the other-than-temporary impairments are considered realized losses and will reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. Amounts prior to 2006 were not restated as the other-than-temporary impairments do not affect earnings or AOCI. I&M records unrealized gains and losses from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 10 for additional discussion of nuclear matters.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss). There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the common shareholder's equity section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of December 31, 2006 and 2005 is shown in the following table.

	December 31,	
Components	**2006**	**2005**
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (2,547)	$ (16,421)
CSPCo	3,398	(859)
I&M	(8,962)	(3,467)
KPCo	1,552	(194)
OPCo	7,262	755
PSO	(1,070)	(1,112)
SWEPCo	(6,410)	(5,852)
TCC	-	(224)
TNC	(702)	(111)
Minimum Pension Liability:		
APCo	$ -	$ (189)
CSPCo	-	(21)
I&M	-	(102)
KPCo	-	(29)
PSO	-	(152)
SWEPCo	-	(277)
TCC	-	(928)
TNC	-	(393)
SFAS 158 Adoption:		
APCo	$ (52,244)	$ -
CSPCo	(25,386)	-
I&M	(6,089)	-
OPCo	(64,025)	-
SWEPCo	(12,389)	-
TNC	(9,457)	-

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo and OPCo are wholly-owned subsidiaries of AEP and PSO, SWEPCo, TCC and TNC are owned by a wholly-owned subsidiary of AEP, therefore, none are required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on the Registrant Subsidiaries' previously reported results of operations or changes in shareholders' equity.

On its Consolidated Balance Sheet, SWEPCo reclassified $147 million of mining equipment as of December 31, 2005 from Production to Other within Property, Plant and Equipment.

On their statements of income, the Registrant Subsidiaries reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. The following table shows the credits reclassified by the Registrant Subsidiaries in 2005 and 2004:

	Year Ended December 31,	
	2005	2004
Company	(in thousands)	
AEGCo	$ 197	$ 189
APCo	912	831
I&M	25,008	14,415
TCC	4,452	8,569

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

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 final pronouncements that we have determined relate to our operations.

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

The FASB issued SFAS 123R, requiring 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.

In 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 FASB Staff Positions (FSP) 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 in 2006. The Registrant Subsidiaries adopted SFAS 123R using the modified prospective method without materially affecting their results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In 2005, the FASB issued SFAS 154. The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. It requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. It also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 was effective for accounting changes and corrections of errors after January 1, 2006 and is applied as necessary.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption.

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. Management expects that the adoption of this standard will impact MTM valuations of certain contracts, but is unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. The Registrant Subsidiaries will adopt SFAS 157 effective January 1, 2008.

SFAS 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"

In September 2006, the FASB issued SFAS 158, amending previous standards. It requires employers to fully recognize the obligations associated with defined benefit pension plans and other postretirement employee benefit (OPEB) plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or OPEB plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions), and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit or OPEB plan affects net periodic benefit costs for the next fiscal year.

The effect of SFAS 158 is to adjust pretax AOCI at the end of each year, for both underfunded deferred benefit and overfunded pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure is volatile based on fluctuating investment returns and discount rates. Favorable changes include higher returns that increase plan assets and higher discount rates that reduce the discounted benefit obligation.

The Registrant Subsidiaries adopted SFAS 158 as of December 31, 2006. They recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of their regulated operations that for ratemaking purposes will be deferred for future recovery. The following table shows the incremental effect of this standard on their financial statements versus prior accounting requirements including the additional minimum pension liability provisions of SFAS 87, "Employers' Accounting for Pensions," which were replaced by SFAS 158 as follows:

	APCo			CSPCo		
	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
	(in thousands)					
Prepaid Benefit Costs	$ 149,915	$ (104,343)	$ 45,572	$ 127,759	$ (92,260)	$ 35,499
Current Accrued Benefit Liability	-	(3,781)	(3,781)	-	(210)	(210)
Noncurrent Accrued Benefit Liability	(17,966)	(96,332)	(114,298)	(3,498)	(41,510)	(45,008)
Regulatory Assets	-	124,080	124,080	-	94,924	94,924
Deferred Income Taxes	110	28,022	28,132	14	13,656	13,670
Additional Minimum Liability	(344)	344	N/A	(41)	41	N/A
Intangible Asset	31	(31)	N/A	2	(2)	N/A
Net of Tax AOCI Equity Reduction	203	52,041	52,244	25	25,361	25,386
Total	$ 131,949	$ -	$ 131,949	$ 124,261	$ -	$ 124,261

	I&M			KPCo		
	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
	(in thousands)					
Prepaid Benefit Costs	$ 78,868	$ (51,941)	$ 26,927	$ 19,056	$ (12,428)	$ 6,628
Current Accrued Benefit Liability	-	(595)	(595)	-	-	-
Noncurrent Accrued Benefit Liability	(2,094)	(58,504)	(60,598)	(100)	(11,947)	(12,047)
Regulatory Assets	-	101,673	101,673	-	24,375	24,375
Deferred Income Taxes	124	3,154	3,278	-	-	-
Additional Minimum Liability	(400)	400	N/A	-	-	N/A
Intangible Asset	45	(45)	N/A	-	-	N/A
Net of Tax AOCI Equity Reduction	231	5,858	6,089	-	-	-
Total	$ 76,774	$ -	$ 76,774	$ 18,956	$ -	$ 18,956

	OPCo			PSO		
	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
	(in thousands)					
Prepaid Benefit Costs	$ 160,400	$ (110,708)	$ 49,692	$ 78,748	$ (48,587)	$ 30,161
Current Accrued Benefit Liability	-	(237)	(237)	-	(64)	(64)
Noncurrent Accrued Benefit Liability	(6,408)	(80,284)	(86,692)	(1,238)	(24,552)	(25,790)
Regulatory Assets	-	92,729	92,729	-	73,203	73,203
Deferred Income Taxes	110	34,365	34,475	68	(68)	-
Additional Minimum Liability	(398)	398	N/A	(201)	201	N/A
Intangible Asset	84	(84)	N/A	6	(6)	N/A
Net of Tax AOCI Equity Reduction	204	63,821	64,025	127	(127)	-
Total	$ 153,992	$ -	$ 153,992	$ 77,510	$ -	$ 77,510

N/A = Not Applicable

	SWEPCo			TCC		
	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
			(in thousands)			
Prepaid Benefit Costs	$ 78,539	$ (52,510)	$ 26,029	$ 111,889	$ (76,315)	$ 35,574
Current Accrued Benefit Liability	-	(70)	(70)	-	(228)	(228)
Noncurrent Accrued Benefit Liability	(1,170)	(26,129)	(27,299)	(2,258)	(28,565)	(30,823)
Regulatory Assets	-	59,649	59,649	-	105,108	105,108
Deferred Income Taxes	114	6,557	6,671	392	(392)	-
Additional Minimum Liability	(326)	326	N/A	(1,120)	1,120	N/A
Intangible Asset	-	-	N/A	-	-	N/A
Net of Tax AOCI Equity Reduction	212	12,177	12,389	728	(728)	-
Total	$ 77,369	$ -	$ 77,369	$ 109,631	$ -	$ 109,631

	TNC		
	Before Application of SFAS 158	Incremental Effect	After Application of SFAS 158
		(in thousands)	
Prepaid Benefit Costs	$ 45,115	$ (32,248)	$ 12,867
Current Accrued Benefit Liability	-	(111)	(111)
Noncurrent Accrued Benefit Liability	(1,100)	(11,524)	(12,624)
Regulatory Assets	-	29,334	29,334
Deferred Income Taxes	175	4,917	5,092
Additional Minimum Liability	(500)	500	N/A
Intangible Asset	-	-	N/A
Net of Tax AOCI Equity Reduction	325	9,132	9,457
Total	$ 44,015	$ -	$ 44,015

N/A = Not Applicable

SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities.

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.

FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48)

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. Although management is in the process of evaluating the impact of FIN 48, management estimates the effect of this interpretation on each of the Registrant Subsidiaries' financial statements will be an unfavorable adjustment to retained earnings of less than $1 million except for the following:

Company	(in millions)
APCo	$ 7
OPCo	3
TCC	2

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Purchases or sales of inventory transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. The Registrant Subsidiaries implemented this issue beginning April 1, 2006 without a material impact on their financial statements.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed. The EITF's decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

As disclosed in Note 1, the Registrant Subsidiaries act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on their customers. Their policy is to present these taxes on a net basis. The Registrant Subsidiaries do not recognize these taxes as revenues or expenses. Therefore, this issue did not impact their financial statements.

SAB No. 108 "Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements" (SAB 108)

In September 2006, the SEC staff issued SAB 108 addressing diversity in practice when quantifying the effect of an error on financial statements. It provides guidance on the consideration of the effects of prior year misstatements in quantifying misstatements in current year financial statements. The Registrant Subsidiaries' adoption of SAB 108, effective December 31, 2006, did not have a material impact on their 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 business combinations, revenue recognition, liabilities and equity, derivatives disclosures, leases, insurance, 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.

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in Extraordinary Loss on Stranded Cost Recovery, Net of Tax on TCC's 2005 Consolidated Statement of Operations (see "TCC Texas Restructuring" section of Note 4).

In 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC recorded this adjustment as an extraordinary item in accordance with SFAS 101. This adjustment is included in Extraordinary Loss on Stranded Cost Recovery, Net of Tax on TCC's 2004 Consolidated Statement of Operations.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Asset Retirement Obligations

In 2005, certain Registrant Subsidiaries recorded a net of tax loss as a cumulative effect of accounting change for ARO in accordance with FIN 47. The following is a summary by Registrant Subsidiary of the cumulative effect of changes in accounting principles recorded in 2005 for the adoption of FIN 47 (no effect on AEGCo, I&M, KPCo, PSO or TCC):

	FIN 47 Cumulative Effect	
	Pretax Loss	Net of Tax Loss
Company	(in millions)	
APCo	$ (3.5)	$ (2.3)
CSPCo	(1.3)	(0.8)
OPCo	(7.0)	(4.6)
SWEPCo	(1.9)	(1.3)
TNC	(13.0)	(8.5)

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the Registrant Subsidiaries.

Other Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $12.8 million at December 31, 2006 and $15.8 million at December 31, 2005, net of accumulated amortization and is included in Deferred Charges and Other on SWEPCo's Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization are:

		December 31, 2006		December 31, 2005	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced Royalties	10	$ 29.4	$ 16.6	$ 29.4	$ 13.6

Amortization of the intangible asset was $3 million per year for 2006, 2005 and 2004. SWEPCo's estimated total amortization is $3 million per year for 2007 through 2010 and $1 million in 2011, when the asset will be fully amortized with no residual value.

The Registrant Subsidiaries have no intangible assets that are not subject to amortization.

4. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. This note is a discussion of pending rate matters, including industry restructuring and customer choice related proceedings, that could materially impact results of operations and cash flows.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans – Affecting CSPCo and OPCo

Ohio restructuring legislation provided for a transition to market pricing for power supply beginning on January 1, 2006. Open access to power suppliers began in Ohio on January 1, 2001 with a five-year transition to market pricing. Under a 2000 PUCO-approved settlement agreement, CSPCo and OPCo (the Ohio companies) froze their rates through December 31, 2005. In accordance with the approved settlement agreement, CSPCo and OPCo amortize their stranded generation-related transition regulatory assets commensurate with recovery through their frozen rates and starting January 1, 2006 through rate riders that expire in 2008 and 2007, respectively. To date, CSPCo and OPCo have lost very few customers to competing suppliers.

In 2005, the PUCO approved Rate Stabilization Plans (RSPs) for the Ohio companies effective January 1, 2006 and ending December 31, 2008, which allow the Ohio companies to increase their generation rates over three years. The approved three-year RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7% a year, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year to recover governmentally-mandated costs. During 2006 through 2008, the RSPs also allow the Ohio companies to recover regulatory assets for 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs, net of financial transmission rights (FTR) revenues, related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program.

Pretax earnings increased by $34 million and $76 million, respectively, for CSPCo and OPCo from the RSP rate increases, net of the amortization of RSP regulatory assets. This increase includes the recovery of unrecognized equity carrying costs for 2004 and 2005. At December 31, 2006, CSPCo's and OPCo's unrecognized equity costs total $4 million and $25 million, respectively. As of December 31, 2006, the unamortized RSP regulatory assets to be recovered through December 31, 2008 for CSPCo and OPCo were $6 million and $32 million, respectively.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court challenging the RSPs and also arguing there is no POLR obligation the Ohio companies are entitled to recover. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies and remanded the case to the PUCO for further proceedings. In August 2006, the PUCO acted on the Ohio companies' remand case ordering them to file a plan to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective. Accordingly, the Ohio companies continue collecting RSP revenues, amortizing the RSP costs, and realizing and recognizing related equity carrying costs.

In September 2006, the Ohio companies submitted their proposal to the PUCO to provide additional options for customer participation in the electric market. The proposal provides for the recovery of the cost of providing the additional options. In January 2007, the PUCO set a schedule for interested persons to file comments concerning the proposal.

The Ohio Supreme Court did not address any other issues raised on appeal, stating its decision did not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. Management believes that the RSP regulatory assets remain probable of recovery and that the Ohio companies will continue to collect RSP revenues.

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally mandated costs.

CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans. At this time, management is unable to predict whether the Ohio companies will transition to market pricing, whether the RSP will be extended with or without modification, or whether cost-based regulation will be reinstated on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals – Affecting CSPCo and OPCo

As provided in the restructuring settlement agreement approved by the PUCO in 2000, CSPCo and OPCo established regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general rate filing to change distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next distribution rate filing to change rates after the end of the RSP period dated December 31, 2008. Through December 31, 2006, CSPCo and OPCo incurred $49 million and $50 million, respectively, of such costs and established regulatory assets of $25 million and $24 million, respectively, for such costs. CSPCo and OPCo have each not recognized $5 million of equity carrying costs which are not recognizable until collected. 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.

IGCC Plant – Affecting CSPCo and OPCo

In March 2005, the Ohio companies filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent 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 costs. 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 under their RSPs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over no more than a twelve-month period effective July 1, 2006. Through December 31, 2006, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $6 million of those costs. The Ohio companies are currently recovering the remaining amounts through June 30, 2007. In its June order, the PUCO indicated that if the Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest. 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.

In August 2006, the Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. Management believes that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, the Ohio companies could be required to refund Phase I cost-related recoveries.

Transmission Rate Filing – Affecting CSPCo and OPCo

In accordance with the RSPs, in December 2005, the PUCO approved the recovery of certain RTO transmission costs through separate transmission cost recovery riders for the Ohio companies. The transmission cost recovery riders are subject to an annual true-up process. In May 2006, the PUCO issued an order approving a two-step increase in the transmission cost recovery riders effective April 1, 2006. The Ohio companies implemented the new tariffs in June 2006. They reflect the Ohio companies' share of the loss of SECA revenues in step one. The step two increase, effective August 1, 2006, reflects the change in the AEP East Zone transmission rate approved by the FERC related to completion of the new Wyoming-Jacksons Ferry 765 kV line.

In October 2006, the Ohio companies filed for initial true-ups under the transmission cost recovery riders. The filings reflect the refund of a regulatory liability, as of September 30, 2006, of $12 million and $16 million for CSPCo and OPCo, respectively, including carrying charges. These refunds were reflected as part of new transmission cost recovery riders, which became effective for 2007. The net effect of the new transmission cost recovery riders is to increase cost recoveries in 2006 over 2005 levels for CSPCo and OPCo by $27 million and $36 million, respectively. CSPCo and OPCo anticipate a favorable net effect in 2007 over 2005 levels of $15 million and $18 million, respectively.

Distribution Service Reliability and Restoration Costs – Affecting CSPCo and OPCo

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 for the Ohio companies to meet. In July 2006, based on a staff report on service reliability and responses filed by the Ohio companies, the PUCO directed the Ohio companies to earmark $10 million for future measures to improve service reliability without recovery. The PUCO further indicated that it will determine where and how to expend the $10 million.

The Ohio companies implemented storm cost recovery riders effective with September 2006 billings, to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. The riders will continue until they have collected the authorized amounts or one year, whichever is shorter.

As a result, at December 31, 2006 CSPCo and OPCo have regulatory assets of $4 million and $3 million, respectively, for these costs.

Distribution Reliability Plan – Affecting CSPCo and OPCo

In January 2006, the Ohio companies initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, the Ohio companies filed a proposed enhanced reliability plan. The plan contemplates CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen-month period beginning July 2007. A hearing is scheduled for April 2007. The OCC filed testimony, which argues that the Ohio companies should be required to improve their distribution service reliability with funds from their existing rates. Management is unable to predict the outcome of this proceeding.

Ormet – Affecting CSPCo and OPCo

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, under a settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by the Ohio companies of the difference between $43 per MWH to be paid by Ormet for power and a market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, the Ohio companies submitted a market price of $47.69 per MWH, which is pending PUCO approval.

<u>Texas Rate Matters</u>

TCC TEXAS RESTRUCTURING – Affecting TCC

TCC's True-up Proceedings and 2002 Securitization

Texas Restructuring Legislation established customer choice on January 1, 2002 and allowed electric utility companies to file for recovery of securitizable stranded generation plant costs, generation-related regulatory assets and non-securitizable other restructuring true-up items. These recoverable and refundable items were recorded as true-up regulatory assets and liabilities.

In 2002, TCC securitized $797 million to recover most of its stranded generation related regulatory assets. TCC sold its generating units to establish its stranded costs and recorded an impairment loss, which resulted in an additional net true-up regulatory asset recoverable under the Texas Restructuring Legislation. Beginning in 2002, TCC also recorded wholesale capacity auction true-up revenues and debt-related carrying costs on its net true-up regulatory asset, as additional true-up regulatory assets. Unrecognized equity carrying costs of $224 million included in the net stranded generation cost to be securitized will be recognized, as collected through transition charge securitization revenues, over the fourteen-year term of the securitization bonds.

In December 2004, predominately based on a PUCT disallowance of a specific stranded cost item in other true-up proceedings, TCC reduced its true-up regulatory assets.

In February 2006, the PUCT issued an order in TCC's True-up Proceeding, which determined that TCC's recoverable net true-up regulatory asset, for both securitizable net stranded generation cost regulatory assets and net other true-up items regulatory liabilities, was $1.475 billion as of September 30, 2005. The order disallowed specific items which included, among other things, a significant portion of TCC's wholesale capacity auction true-up revenues and a portion of TCC's stranded costs determined from the sale of the ERCOT generating units. Based on the PUCT's order in December 2005, TCC reduced its true-up regulatory asset. The order also identified a reduction in the net recoverable amount, which represented the present value benefit of ADITC and EDFIT related to the plants sold. See "TCC's 2006 CTC Proceeding" section below.

TCC will recover its PUCT-approved net true-up regulatory asset under the Texas Restructuring Legislation using two mechanisms: (a) by issuing securitization bonds in the amount of its net stranded generation costs and implementing a transition charge (TC) rate rider to collect the bond interest and principal over the term of the bonds and (b) by implementing a competition transition charge (CTC) rate rider credit to refund its net regulatory liability for other true-up items.

TCC's 2006 Securitization Proceeding

TCC filed an application in March 2006 requesting recovery through the issuance of securitization bonds of $1.804 billion of PUCT-approved securitizable net stranded generation costs plus subsequent carrying costs through August 31, 2006 and issuance costs. The securitization request excluded TCC's net true-up regulatory liability for other true-up items, which will be refunded to customers using a CTC rate rider credit. See the "TCC's 2006 CTC Proceeding" section of this note. The PUCT approved a settlement in June 2006, which reduced the securitizable amount by $77 million and settled several issues and authorized the issuance of securitization bonds of $1.72 billion as of August 31, 2006. TCC issued securitization bonds on October 11, 2006 for $1.74 billion, which included additional issuance and carrying costs through October 11, 2006.

The securitization order provides for TCC to recover the securitization bond principal and related interest expense from customers over the fourteen-year term of the securitization bonds. Beginning in October 2006, the Securitized Transition Asset is amortized based on the ratio of annual transition revenues to total revenues over the fourteen-year TC collection period.

The June 2006 securitization order reduced the amount to be securitized and recovered by the present value of the ADITC and EDFIT benefit identified above in the April 2006 final true-up order. The securitization order also identified the present value cost-of-money benefit generated through the final year the securitization bonds will be outstanding (fourteen years) as an additional reduction. The present value cost-of-money benefit of $315 million resulted from the ADFIT related to the generation assets. However, rather than reducing the amount to be securitized, the PUCT ordered TCC to refund the ADFIT benefit through the CTC. See the "TCC's 2006 CTC Proceeding" section below for further details.

TCC's 2006 CTC Proceeding

In June 2006, TCC filed to refund, through a CTC rate rider credit, its net other true-up items and the ADFIT cost-of-money benefit less the present value benefit of ADITC and EDFIT, discussed above. An interim order required that the CTC refund begin in October 2006 pending a final CTC decision. The PUCT issued a final order in December 2006, which required that TCC refund $356 million of other true-up items and $19 million in estimated interest through the CTC over twenty-one months starting in October 2006. The ADFIT cost-of-money benefit of $315 million has a retrospective portion of $75 million which has been expensed and a prospective portion of $240 million which will be amortized to expense over the fourteen-year securitization bond term consistent with the period over which the cost-of-money benefit is generated and computed in the securitization order. The difference between the amount being refunded and the net other true-up regulatory liability of $219 million ($155 million at December 31, 2006) is predominantly due to the inclusion in the CTC refund of the $240 million unrecorded prospective portion of the ADFIT cost-of-money benefit less the $61 million present value benefit of ADITC and EDFIT applied to reduce the amount securitized above plus $42 million of interest through the date of securitization. The $103 million will be deferred pending a final determination of whether a normalization violation would occur. See “Other Texas Restructuring Matters” section below for further details.

TCC will accrue interest expense until its net CTC refund is completed. The interest expense on the net CTC amount is $22 million for the year ended December 31, 2006 and is included in Interest Expense on TCC’s 2006 Consolidated Statement of Income.

Impairment Assessment of Net True-up Regulatory Assets

TCC performed a probability of recovery impairment test on TCC’s recorded net true-up regulatory asset as of September 30, 2006, after receipt of the final securitization order, and again as of December 31, 2006 after receipt of the final CTC order. At both dates, TCC determined that the projected net cash flows from the securitization less the proposed CTC refund would provide more than sufficient net positive cash flows to recover TCC’s recorded net true-up regulatory asset. Accordingly, no impairment was recorded at either date.

At December 31, 2006, TCC’s Consolidated Balance Sheet reflects a securitization bond liability of $2.335 billion of which $595 million is from the initial 2002 securitization, a securitization transition asset of $2.158 billion of which $542 million is from the initial 2002 securitization, and a net true-up regulatory liability for other true-up items of $155 million.

Texas District Court Appeal Proceedings

TCC appealed the PUCT orders seeking relief in both state and federal court on the grounds that the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the statute and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues,
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled out of the money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC’s net stranded generation plant cost, and
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation. See “TCC and TNC Deferred Fuel” and “TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes” sections below.

Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC’s true-up recoveries. On February 1, 2007, the Texas District Court judge hearing the various appeals issued a letter containing his preliminary determinations. He generally affirmed the PUCT’s April 4, 2006 final true-up order with two significant exceptions. The judge determined that the PUCT erred when it determined TCC’s stranded cost using the sale of assets method instead of the Excess Cost Over Market (ECOM) method to value TCC’s nuclear plant. The judge also determined that the PUCT erred when it concluded it was required to use the carrying cost rate specified in the true-up order. However, the District Court did not rule that the carrying cost rate was inappropriate. He directed that these matters should be remanded to the PUCT to determine their specific impact on TCC’s future revenues.

In response to a request by TCC, the District Court judge will hear additional argument on March 22, 2007 regarding use of the ECOM method to value TCC’s nuclear plant stranded cost. TCC anticipates that the final judgment will be entered after that hearing. TCC intends to appeal any final adverse rulings of the District Court regarding these two matters along with certain of the judge’s other preliminary determinations that affirm the PUCT’s decisions. It is possible that the PUCT could also appeal any final adverse rulings regarding these two matters.

Although management cannot predict the ultimate outcome of these preliminary District Court determinations, any future remanded PUCT proceedings or any future court appeals, management concluded it is probable the District Court's preliminary ruling regarding the use of an ECOM method in lieu of a sales method to determine securitizable stranded cost will not be upheld on appeal. The judge has also determined in his letter ruling that if the sales method is permitted for valuing the nuclear plant, the PUCT improperly reduced stranded costs in connection with the sales process, which could have a materially favorable effect on TCC.

Management also concluded if the District Court's preliminary carrying cost rate ruling is ultimately remanded to the PUCT for reconsideration, the PUCT could either confirm the existing carrying cost rate or redetermine the rate. If the PUCT changes the rate, it could result in a material adverse change to TCC's recoverable carrying costs. However, management cannot predict what actions, if any, the PUCT will take regarding the carrying costs.

If the District Court judge's original determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. TCC cannot estimate the amount at this time, but the amount could exceed its Common Shareholder's Equity at December 31, 2006. If it were finally concluded that the ECOM method must be used to value TCC's nuclear plant stranded cost, and/or that the PUCT's rule on carrying costs was invalid, it could, after the PUCT remand decisions, have a substantial adverse impact on future results of operations, cash flows and financial condition.

If TCC ultimately succeeds in its appeals on other than the above two matters, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, including their appeals of the two matters discussed above, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes – Affecting TCC

In TCC's true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated that the PUCT's flow-through to customers of the present value of the ADITC and EDFIT benefits would result in a normalization violation. To address the matter, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. It is anticipated that if the normalization issue is resolved consistent with the PUCT's treatment, TCC will then refund $103 million plus additional carrying costs. If such refund is ultimately determined to cause a normalization violation, TCC anticipates it will be permitted to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of December 31, 2006, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. 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 nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel – Affecting TCC and TNC

The TCC deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC discussed above. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered a reduction in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins under a FERC-approved SIA. Both TCC and TNC appealed the

PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margin allocations in the federal court. Intervenors also appealed the PUCT's rulings in state court.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales allocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. TCC awaits a ruling in their appeal. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the regulatory liabilities.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then existing SIA allocation method. 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. Although management cannot predict the ultimate outcome of this federal litigation, management believes that its allocations were in accordance with the then existing FERC-approved SIA.

In January 2007, TCC began refunding as part of the CTC rate rider credit described above, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund relating to the favorable Federal District Court order may be subject to being refunded only upon a successful appeal by the PUCT. See "TNC's True-up Proceeding" section below for status of TNC's over-recovered fuel refund.

Excess Earnings – Affecting TCC

In 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. To date, TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. The Supreme Court of Texas requested briefing, which has been provided, but it has not decided whether it will hear the case. If the Court of Appeals decision is upheld and the refund mechanism is found to be unlawful, the impact on TCC would then depend on: (a) how and if TCC is ordered by the PUCT to refund the excess earnings to ultimate customers and (b) whether it will be able to recover the amounts previously refunded to the REP including the REP TCC sold to Centrica. Management is unable to predict the ultimate outcome of this litigation and its effect on future results of operations and cash flows.

TNC's True-up Proceeding – Affecting TNC

TNC filed with the PUCT in August 2005 to establish a credit rider to refund its $21 million net true-up regulatory liability. In December 2005, that proceeding was suspended, pending a final ruling from TNC's appeal to the federal court regarding the fuel proceeding (described above). In August 2006, the suspension was lifted and the proceeding resumed. The PUCT approved a settlement that recommended implementing a $13 million interim refund over six months beginning in September 2006 of the net true-up regulatory liability, exclusive of the $8 million federal court fuel issue. TNC is accruing interest expense on the unrefunded balance and will continue to do so until the balance is fully refunded. TNC anticipates a final PUCT decision regarding this proceeding in 2007. The appeals to the state and federal courts are ongoing.

Texas Restructuring – SPP – Affecting TNC and SWEPCo

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo's and approximately 3% of TNC's businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007. The Arkansas Public Service Commission's approval requires SWEPCo to amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

OTHER TEXAS RATE MATTERS

ERCOT PTB Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and the 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 respective former affiliated REPs). In 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 in 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the decision to the Supreme Court of Texas, which ordered full briefing. In February 2007, the Supreme Court of Texas denied review. No motions for rehearing have been filed and management believes the matter is now final.

TCC and TNC Energy Delivery Base Rate Filings – Affecting TCC and TNC

TCC and TNC each filed a rate case for recovery of the cost of transmission and distribution energy delivery services (wires) in Texas. TCC and TNC requested $81 million and $25 million in annual increases, respectively. Both requests include a return on common equity of 11.25% and the impact of the expiration of the CSW merger savings rate credits. TCC and TNC expect the new base wires rates to become effective, subject to refund, in the second quarter of 2007 with a decision from the PUCT expected in the third quarter of 2007.

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 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 in April 2006 that they would not pursue the matter further.

SWEPCo Fuel Reconciliation – Texas – Affecting SWEPCo

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations. SWEPCo sought, in the proceedings, to include underrecoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The intervenor recommendations ranged from a $10 million to $28 million reduction. In February 2007, the PUCT staff filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced by $10 million. SWEPCo does not agree with the intervenor's or staff's recommendations and filed rebuttal testimony in February 2007. Management is unable to predict the outcome of this proceeding or its effect on future results of operations and cash flows.

<u>Virginia Rate Matters</u>

Virginia Restructuring – Affecting APCo

In April 2004, the Governor of Virginia signed legislation that extended the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the restructuring law, APCo is deferring incremental environmental generation costs and incremental reliability costs for future recovery and is amortizing a portion of such deferrals commensurate with recovery. See the "APCo Virginia Environmental and Reliability Costs" section below for further details.

In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. We are in the process of evaluating the impact of the legislation if it is signed into law.

APCo Virginia Environmental and Reliability Costs – Affecting APCo

The amended 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 on and 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 1, 2004 through September 30, 2005.

In November 2006, the Virginia SCC issued a final order that rejected the staff's and the Hearing Examiner's interpretation of the law, which would have resulted in the inability to record a regulatory asset and would have ultimately prevented APCo from recovering its full incremental E&R costs incurred since July 1, 2004. The order approved an increase in APCo's rates to recover $21 million of incremental E&R costs previously incurred from July 1, 2004 through September 30, 2005 by means of a surcharge, effective December 1, 2006 through November 30, 2007. As a result, in the fourth quarter of 2006, APCo commenced recovery of the approved E&R rate rider and deferred as a regulatory asset, $60 million of incremental E&R costs incurred from July 1, 2004 through September 30, 2006 based on the Virginia SCC's order and reversed $11 million of related AFUDC and capitalized interest, thereby increasing pre-tax earnings by $49 million. In addition, APCo has identified but not recognized $10 million of equity carrying costs on incremental E&R capital expenditures, which are not recognizable until collected. The order requires APCo to keep track, for true-up purposes, of base rate and surcharge recoveries of incremental E&R costs on a continuing basis to avoid any double recovery. During 2007, APCo will file for recovery of incremental E&R costs incurred from October 1, 2005 through September 30, 2006. The Virginia base rate case increase implemented October 2, 2006, subject to refund, is currently recovering an ongoing level of incremental E&R costs incurred since September 30, 2006 and as a result, ceased deferring such costs incurred after that date.

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 the cost of its investment in environmental equipment and a return on equity of 11.5%. 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 trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which is estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request include $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase being collected, subject to refund, includes recovery of incremental E&R costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovery sought through the E&R surcharge mechanism previously discussed if not recovered through base rates. In October 2006, the Virginia SCC staff filed their direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. Management reserved a portion of the revenue subject to refund that in its opinion is not probable of recovery. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006. APCo expects a ruling during 2007. Management is unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

West Virginia Rate Matters

APCo West Virginia Rate Case – Affecting APCo

In July 2006, the WVPSC approved a settlement agreement reached by APCo and WPCo and the WVPSC staff and intervenors in connection with a West Virginia rate case filed in 2005. The settlement agreement provided for an initial overall increase in rates of $40 million effective July 28, 2006 comprised of:

- A $50 million increase in Expanded Net Energy Cost (ENEC) for fuel, purchased power expenses, off-system sales credits and other energy-related costs (the ENEC is an expanded form of a fuel clause mechanism which includes all energy-related costs);
- A $21 million special construction surcharge providing recovery of the costs of scrubbers and the new Wyoming-Jacksons Ferry 765 kV line to date;
- A $16 million general base rate reduction resulting predominantly from a reduction in the return on equity to 10.5% and a $9 million reduction in depreciation expense which affects cash flows but not earnings; and
- A $15 million credit to refund a portion of deferred prior over-recoveries of ENEC recorded in regulatory liabilities on APCo's Consolidated Balance Sheets, which will impact cash flows but not earnings.

In addition, the agreement provided a mechanism that allows APCo and WPCo to adjust their special construction surcharges annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at APCo's Mountaineer and John Amos power plants and the costs of the new Wyoming-Jacksons Ferry 765 kV line. APCo plans to file in March 2007 with the WVPSC for the first adjustment to their special construction surcharge, providing an incremental annual increase of $26 million to be effective July 1, 2007. APCo estimates annual increases in revenues of $13 million effective July 1, 2008 and $16 million effective July 1, 2009, subject to subsequent review by the WVPSC.

Under the settlement, the ENEC mechanism was reinstated effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel, purchased power costs, off-system sales margins and other energy-related costs beginning in 2007. The settlement provides for the return to customers of the remaining portion of the prior ENEC regulatory liability plus interest at a LIBOR rate (London Interbank Offered Rate) on the unrefunded balance in future ENEC proceedings.

APCo IGCC – Affecting APCo

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, WV. In January 2007, the WVPSC issued an order delaying the Commission's deadline for issuing an order on the certificate to December 3, 2007. The order also cancels a previously-approved procedural schedule. Through December 31, 2006, APCo deferred pre-construction IGCC costs totaling $10 million.

Indiana Rate Matters

I&M Depreciation Study Filing – Affecting I&M

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. An order issued by the IURC in October 2006 did not dispute our revised depreciation accounting rates but, nevertheless, denied I&M's request to revise its book depreciation rates between base rate cases. In November 2006, I&M filed with the IURC a petition for reconsideration of the October order as well as a notice of appeal to the Indiana Court of Appeals. In January 2007, the IURC denied I&M's petition for reconsideration.

In February 2007, I&M withdrew its appeal of the IURC order and filed a new request with the IURC for approval of the revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counselor that would provide direct benefits to I&M's customers if new depreciation rates are approved by the IURC. The direct benefits would include a $5 million credit in fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement is approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the 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 Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed the book depreciation reduction would increase earnings but would not impact cash flows until rates are revised. I&M requested expeditious review and approval of its filing, but management cannot predict the outcome of the request.

Kentucky Rate Matters

KPCo Rate Filing – Affecting KPCo

In March 2006, the KPSC approved a settlement agreement in KPCo's 2005 base rate case. The approved agreement provided 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 was 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 AFUDC.

KPCo Environmental Surcharge Filing – Affecting KPCo

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo requested recovery of approximately $2 million of additional revenue in 2007 and an additional $6 million in 2008 for a total of $8 million of additional revenue. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge.

In November 2006, the Kentucky attorney general and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005 Environmental Surcharge order. In its order, the KPSC approved KPCo's recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs it incurs as a result of the AEP Power Pool capacity settlement. The KPSC allowed KPCo to recover these FERC-approved allocated costs, via the environmental surcharge, since the KPSC's first order in the environmental surcharge case in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates.

Oklahoma Rate Matters

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 eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduce its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 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 and with $9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had 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. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC 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 sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its position. Management believes that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should 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 could 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.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and PSO expects a recommendation from the ALJ in 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. In compliance with an OCC order, PSO is required to file its testimony by June 15, 2007. This proceeding will cover the year 2005.

Management cannot predict the outcome of the pending fuel and purchase power reviews or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

PSO Rate Filing – Affecting PSO

In November 2006, PSO filed a request to increase base rates $50 million for Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007. PSO seeks a return on equity of 11.75%. PSO also proposed a formula rate plan that, if approved as filed, will permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve-months beginning six months after the test year. The formula would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and avoid recording a large amount of AFUDC that would have been recorded during the construction time period. Hearings are scheduled to begin in May 2007.

Louisiana Rate Matters

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 Louisiana Compliance Filing – Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%.

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, based on a proposed 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo will file testimony in the first quarter of 2007. Hearings are expected to occur in early 2007. A decision is not expected until mid or late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations and cash flows.

Michigan Rate Matters

Michigan Restructuring – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective on that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. As of December 31, 2006, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2006, the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

FERC Rate Matters

RTO Formation/Integration Costs – 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 AEP East companies deferred unamortized RTO and PJM formation/integration costs were as follows:

	December 31, 2006		December 31, 2005	
Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)			
APCo	$ 3.7	$ 4.7	$ 4.1	$ 4.9
CSPCo	1.5	1.9	1.7	1.9
I&M	2.9	3.4	3.2	3.7
KPCo	0.9	1.1	1.0	1.1
OPCo	4.2	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 and related carrying costs not billed by PJM in monthly charges from November 1, 2005 through May 31, 2020. The rate, the result of a settlement, will be adjusted each year to collect $2 million on an annualized basis for 175 months. 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 approximately 85% of the transmission load in the AEP zone. As a result, the AEP East companies will need to recover the 85% through their retail rates.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of the deferred PJM-billed integration costs, including related carrying charges, of AEP, Commonwealth Edison Company (ComEd) and The Dayton Power and Light Company from all present zones of the PJM region, except the Virginia Electric & Power Company (VEPCo) zone. The net result of the settlement is that the AEP East companies will recover approximately 50% of the deferred PJM-billed integration costs from third parties, and will need to recover the remaining 50% through retail rates.

As a result of recently approved rate increases, CSPCo, OPCo, KPCo and APCo recover the amortization of RTO formation/integration costs billed to the AEP East companies in Ohio, Kentucky, Virginia (subject to refund) and West Virginia. In Indiana, I&M is subject to a rate cap until June 30, 2007 and is precluded from recovering its share of the deferred RTO costs until that date or until it can file for a rate increase in Indiana. I&M has not yet filed for recovery in Michigan.

If the Virginia, Indiana or Michigan commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it could adversely impact future results of operations and cash flows. In the event of a disallowance, AEP would appeal that decision to the appropriate state or federal courts.

Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M, KPCo and OPCo

<u>*SECA Revenue Subject to Refund*</u>

The AEP East companies eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues as follows:

	Year Ended December 31,		
	2006 (a)	**2005**	**2004**
Company		**(in millions)**	
APCo	$ 13.4	$ 52.4	$ 4.4
CSPCo	7.9	28.4	2.5
I&M	8.1	30.4	2.8
KPCo	3.2	12.4	1.0
OPCo	10.4	39.4	3.5

(a) Represents revenues through March 31, 2006, when SECA rates expired, and excludes all provisions for refund**.**

Approximately $19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these SECA billings.

In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. It would also provide insignificant refunds of SECA rates paid by the AEP East companies. Based on the completed settlements and before the issuance of the ALJ's initial decision, the AEP East companies initially provided a reserve for $22 million in net refunds.

AEP, together with Exelon and DP&L, filed an extensive post hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. As a consequence, an additional $15 million reserve was recorded in December 2006.

The AEP East companies provided for net refunds as shown in the following table:

	Year Ended December 31,		
	2006	2005	2004
Company		(in millions)	
APCo	$ 11.0	$ 1.0	$ -
CSPCo	6.1	0.6	-
I&M	6.4	0.6	-
KPCo	2.6	0.2	-
OPCo	8.3	0.8	-

Although management believes it has meritorious arguments, they cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate 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 and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of 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.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in additional revenues per year for AEP East companies from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV, which would produce lower revenues for AEP East companies than the AEP/AP proposal.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would produce considerably lower revenues for AEP East companies than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design that would include all transmission facilities, which would produce higher transmission revenues for AEP East companies than the AEP/AP proposal.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favor continuation of the existing PJM rate design. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC and the Postage Stamp rate proposed by the FERC staff to be just and reasonable alternatives and recommended that the FERC staff's Postage Stamp rate proposal be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP East companies than the AEP/AP proposal. The phase-in of Postage Stamp rates would delay the full impact of that result until about 2012.

AEP filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. AEP argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest. A FERC decision is likely before mid-2007.

To recover these lost T&O and SECA rates, the AEP East companies sought to increase their retail rates in most of their states. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of their share of the transmission revenue reduction in new rates effective March 30, 2006.
- In Ohio, CSPCo and OPCo recover their FERC-approved OATT that reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of their share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of their share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising their rates until July 1, 2007.
- In Michigan, I&M has not filed to seek recovery of the lost transmission revenues.

The AEP East companies presently recover from retail customers approximately 85% of the reduction in transmission revenues of $128 million a year.

Once approved by the FERC, the favorable impacts of the new regional PJM rate design will flow directly to wholesale customers and to retail customers in West Virginia through the ENEC and to retail customers in Ohio upon PUCO approval of a filing the Ohio companies would make to reflect the new rates in the Transmission Cost Recovery Rider. In Kentucky, Indiana, Virginia and Michigan, the additional transmission revenues can be expected to reduce retail rates in future base rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. Management believes that the AEP/AP proposal or the Postage Stamp proposal combined with the retail rate recovery discussed above would be an effective replacement for the eliminated T&O and SECA rates. 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. The resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates on a timely basis especially in Indiana, where there is a rate freeze until June 30, 2007, and Michigan.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement which allowed increases in our wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006 when the new Wyoming-Jacksons Ferry 765 kV line went into service. Wholesale transmission revenues increased in 2006 due to this rate increase. Management estimates that this rate increase will increase wholesale transmission revenues in 2007.

The AEP East companies' wholesale transmission revenues approximate increases in 2006 and estimated increases in 2007 are shown in the following table:

	Wholesale Transmission Revenues	
	2006	**2007**
Company	**(in millions)**	
APCo	$ 7.0	$ 10.5
CSPCo	5.3	7.9
I&M	4.4	7.0
KPCo	1.7	2.4
OPCo	4.2	6.7
Total	$ 22.6	$ 34.5

Calpine Oneta Power, L.P.'s Request at the FERC for Reactive Power Compensation From SPP – Affecting TNC, PSO and SWEPCo

In April 2003, Calpine Oneta Power (Calpine), an IPP, filed at the FERC a proposed rate schedule to charge SPP for reactive power from Calpine's generating facility. The FERC rate schedule included a fixed annual fee of $2 million. PSO, SWEPCo and, until February 2007, a small portion of TNC operated in SPP. In September 2006, the FERC issued an order reversing an ALJ initial decision, granting Calpine's request and requiring Calpine to make a compliance filing within 30 days. PSO's, SWEPCo's and TNC's share of this SPP expense could be approximately 90% of the total amount billed by Calpine. Based on this information, in 2006 PSO and SWEPCo recorded a provision, including interest, of $4 million and $5 million, respectively, for the retroactive reactive power liability. AEP requested rehearing at the FERC.

Calpine issued invoices to AEP for service and interest charges from June 2003 through December 2006 totaling $10 million. AEP objected to these invoices, in part, on the basis that Calpine seeks to collect its entire revenue requirement from us, leaving us with the risk of collecting the portion that may be owed by other service providers in the AEP zone of SPP. Meanwhile, in December 2006, SPP filed a new rate schedule. If the new rate schedule is approved, it will be generally applicable throughout SPP for reactive power service. If the FERC accepts the new rate, on a going forward basis from March 2007, AEP will owe an immaterial amount to Calpine for its reactive power production capability. The new tariff compensates generators for the reactive service they actually provide rather than the capability they possess.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement – Affecting 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 the proposed methodology effective April 1, 2006 and beyond. The approved allocation methodology for the AEP East companies and AEP West companies 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, which effectively allowed the AEP West companies to share in PJM and MISO regional margins in the East. In February 2006, AEP filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because they are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA effective April 1, 2006 and CSW Operating Agreement effective May 1, 2006. The total trading and marketing margins are unaffected by the allocation methodology. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of expanded net energy fuel clause recovery mechanisms and related off-system sales sharing mechanisms by state.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Our regulated businesses' financial statements are prepared in accordance with the provisions of SFAS 71, as discussed in the "Accounting for the Effects of Cost-Based Regulation" section of Note 1.

Regulatory assets and liabilities are comprised of the following items at December 31:

	TCC			TNC		
	2006	2005	Notes	2006	2005	Notes
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net (Note 13)	$ N/A	$ 20,616	(b) (h) (i)	$ N/A	$ N/A	
SFAS 158 Regulatory Asset (Notes 2 and 9)	105,108	-	(a)	29,334	-	(a)
Designated for Securitization	-	1,435,597	(d)	N/A	N/A	
Wholesale Capacity Auction True-up (Note 4)	-	76,464	(e)	N/A	N/A	
Refunded Excess Earnings (Note 4)	55,608	55,461	(l)	N/A	N/A	
Other	32,395	100,649	(c) (i)	9,068	9,787	(c) (i)
Total Noncurrent Regulatory Assets	$ 193,111	$ 1,688,787		$ 38,402	$ 9,787	
Regulatory Liabilities:						
Asset Removal Costs (Note 17)	$ 246,115	$ 231,990	(g)	$ 87,313	$ 82,639	(g)
Deferred Investment Tax Credits	104,264	105,134	(a) (k)	16,157	17,427	(a) (j)
SFAS 109 Regulatory Liability, Net (Note 13)	18,453	N/A	(b) (h) (i)	9,689	6,828	(b) (h) (i)
CTC Refund	155,030	238,582	(e)	12,865	18,839	(f)
Other	74,165	76,437	(c) (i)	13,405	13,999	(c) (i)
Total Noncurrent Regulatory Liabilities	$ 598,027	$ 652,143		$ 139,429	$ 139,732	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount includes a carrying cost and was included in TCC's True-up Proceeding and securitized in October 2006. The cost of the securitization bonds will be recovered over a fourteen-year period. Amount is included within Securitized Transition Assets on the Consolidated Balance Sheet for 2006. See "TCC Texas Restructuring" section of Note 4.
(e) Net amounts were ordered to be refunded through the CTC. TCC's net refund began on an interim basis in October 2006. In a final order issued December 2006, the PUCT set the final net refund to be completed by June 2008. CTC refunds for TCC accrue interest until the refunds are completed. See "TCC's 2006 CTC Proceeding" section of Note 4.
(f) The PUCT ordered TNC's CTC refund for the six-month period ending February 2007 and will accrue interest until completed. See "TNC's True-up Proceeding" section of Note 4.
(g) The liability, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(h) SFAS 109 Regulatory Asset/Liability, Net is presented on the Balance Sheet at net presentation.
(i) Recovery/refund period - various periods.
(j) Recovery/refund period - up to 16 years.
(k) Recovery/refund period - up to 56 years.
(l) Recovery method and timing to be determined in future proceeding.

N/A = Not Applicable

	AEGCo			APCo		
	2006	2005	Notes	2006	2005	Notes
			(in thousands)			
Regulatory Assets:						
Total Current Regulatory Assets –						
Under-recovered Fuel Costs – Virginia	$ N/A	$ N/A		$ 29,526	$ 30,697	(b) (j)
SFAS 109 Regulatory Asset, Net (Note 13)	$ N/A	$ N/A		$ 365,462	$ 337,544	(a) (h) (i)
Transition Regulatory Assets – Virginia	N/A	N/A		16,978	21,223	(a) (l)
SFAS 158 Regulatory Asset (Notes 2 and 9)	N/A	N/A		124,080	-	(a)
Environmental and Reliability Costs – Virginia (Note 4)	N/A	N/A		58,375	24,430	(c) (i)
Unamortized Loss on Reacquired Debt	4,021	4,258	(b) (p)	15,435	17,652	(b) (q)
Other	1,417	1,314	(a) (i)	41,823	56,445	(a) (i)
Total Noncurrent Regulatory Assets	$ 5,438	$ 5,572		$ 622,153	$ 457,294	
Regulatory Liabilities:						
Total Current Regulatory Liabilities –						
Over-recovered Fuel Costs – West Virginia	$ N/A	$ N/A		$ 11,196	$ -	(b) (f) (j)
Asset Removal Costs	$ 30,896	$ 27,640	(d)	$ 200,582	$ 86,315	(d)
Deferred Investment Tax Credits	39,285	42,718	(c) (n)	21,164	25,723	(c) (m)
SFAS 109 Regulatory Liability, Net (Note 13)	9,469	12,331	(a) (h) (i)	N/A	N/A	
Over-recovered ENEC Costs	N/A	N/A		41,395	52,399	(a) (f) (g)
Other	-	-		46,583	36,793	(a) (i)
Total Noncurrent Regulatory Liabilities	$ 79,650	$ 82,689		$ 309,724	$ 201,230	

	CSPCo			I&M		
	2006	2005	Notes	2006	2005	Notes
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net (Note 13)	$ 17,646	$ 17,723	(a) (h) (i)	$ 111,035	$ 118,743	(a) (h) (i)
Transition Regulatory Assets (Note 4)	97,610	144,868	(a) (k)	N/A	N/A	
SFAS 158 Regulatory Asset (Notes 2 and 9)	94,924	-	(a)	101,673	-	(a)
Cook Nuclear Plant Refueling Outage Levelization	N/A	N/A		46,864	22,971	(a) (g)
Other	88,124	69,008	(a) (i)	55,233	80,972	(c) (i)
Total Noncurrent Regulatory Assets	$ 298,304	$ 231,599		$ 314,805	$ 222,686	
Regulatory Liabilities:						
Asset Removal Costs (Note 17)	$ 121,773	$ 117,942	(d)	$ 293,961	$ 280,819	(d)
Deferred Investment Tax Credits	22,952	25,215	(a) (o)	67,324	75,077	(a) (n)
Excess ARO for Nuclear Decommissioning (Note 10)	N/A	N/A		322,746	271,318	(e)
Other	34,323	22,187	(c) (i)	69,371	82,801	(c) (i)
Total Noncurrent Regulatory Liabilities	$ 179,048	$ 165,344		$ 753,402	$ 710,015	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(e) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, which accrues monthly, and will be paid when the nuclear plant is decommissioned.
(f) In July 2006, the WVPSC approved a settlement to activate the ENEC mechanism. See "APCo and WPCo West Virginia Rate Case" section of Note 4. The current portion is recorded in Other on our Consolidated Balance Sheets.
(g) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
(h) SFAS 109 Regulatory Asset/Liability, Net is presented on the Balance Sheet at net presentation.
(i) Recovery/refund period – various periods.
(j) Recovery/refund period – 1 year.
(k) Recovery/refund period – up to 2 years.
(l) Recovery/refund period – 4 years.
(m) Recovery/refund period – up to 13 years.
(n) Recovery/refund period – up to 16 years.
(o) Recovery/refund period – up to 18 years.
(p) Recovery/refund period – 8 to 19 years.
(q) Recovery/refund period – up to 26 years.

N/A = Not Applicable

	KPCo			OPCo		
	2006	2005	Notes	2006	2005	Notes
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net (Note 13)	$ 100,439	$ 96,578	(a) (g) (h)	$ 158,545	$ 159,742	(a) (g) (h)
Transition Regulatory Assets (Note 4)	N/A	N/A		70,397	139,632	(a) (i)
SFAS 158 Regulatory Asset (Notes 2 and 9)	24,375	-	(a)	92,729	-	(a)
Other	11,325	20,854	(c) (h)	92,509	98,633	(c) (h)
Total Noncurrent Regulatory Assets	$ 136,139	$ 117,432		$ 414,180	$ 398,007	
Regulatory Liabilities:						
Asset Removal Costs (Note 17)	$ 31,165	$ 30,291	(e)	$ 111,319	$ 110,098	(e)
Deferred Investment Tax Credits	4,356	5,500	(a) (l)	6,447	9,416	(c) (l)
Other	13,588	21,003	(h)	68,129	48,978	(c) (h)
Total Noncurrent Regulatory Liabilities	$ 49,109	$ 56,794		$ 185,895	$ 168,492	

	PSO			SWEPCo		
	2006	2005	Notes	2006	2005	Notes
			(in thousands)			
Regulatory Assets:						
Total Current Regulatory Assets – Under-recovered Fuel Costs	$ 7,557	$ 108,732	(f) (i)	$ -	$ 51,387	(f) (i)
SFAS 109 Regulatory Asset, Net (Note 13)	$ N/A	$ N/A		$ 35,495	$ 38,793	(b) (g) (h)
SFAS 158 Regulatory Asset (Notes 2 and 9)	73,203	-	(a)	59,649	-	(a)
Unrealized Loss on Forward Commitments	39,597	18,279	(a) (h)	31,093	13,922	(a) (h)
Unamortized Loss on Reacquired Debt	10,451	12,456	(b) (j)	18,175	17,973	(b) (n)
Other	19,654	19,988	(a) (h)	12,008	11,088	(d) (h)
Total Noncurrent Regulatory Assets	$ 142,905	$ 50,723		$ 156,420	$ 81,776	
Regulatory Liabilities:						
Total Current Regulatory Liabilities – Over-recovered Fuel Costs	$ N/A	$ N/A		$ 26,012	$ 3,181	(f) (i)
Asset Removal Costs (Note 17)	$ 220,286	$ 212,346	(e)	$ 268,323	$ 255,920	(e)
Deferred Investment Tax Credits	26,242	27,273	(a) (m)	27,022	31,246	(a) (k)
SFAS 109 Regulatory Liability, Net (Note 13)	10,706	12,089	(b) (g) (h)	N/A	N/A	
Unrealized Gain on Forward Commitments	58,350	32,932	(a) (h)	44,769	25,213	(a) (h)
Other	-	-		6,660	7,687	(d) (h)
Total Noncurrent Regulatory Liabilities	$ 315,584	$ 284,640		$ 346,774	$ 320,066	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) Amounts are both earning and not earning a return.
(e) The liability, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(f) Over/Under-recovered fuel for SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts for SWEPCo do earn a return. PSO fuel balances began earning a return in June 2005.
(g) SFAS 109 Regulatory Asset/Liability, Net is presented on the Balance Sheet at net presentation.
(h) Recovery/refund period – various periods.
(i) Recovery/refund period – 1 year.
(j) Recovery/refund period – up to 9 years.
(k) Recovery/refund period – up to 11 years.
(l) Recovery/refund period – up to 13 years.
(m) Recovery/refund period – up to 36 years.
(n) Recovery/refund period – up to 37 years.

N/A = Not Applicable

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements.

Summary of key provisions of Merger Rate Agreements beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reductions of $221 million over 6 years. In 2006, TCC and TNC requested to have these rate reductions eliminated. See "TCC and TNC Energy Delivery Base Rate Filings" section of Note 4.
Indiana – I&M	Rate reductions of $67 million over 8 years.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

Potential Losses and Insurance – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The Registrant Subsidiaries maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from third parties and are in excess of retentions absorbed by the Registrant Subsidiaries. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers and various Lloyds of London syndicates.

See Note 10 for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

COMMITMENTS

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. The following table shows the estimated construction expenditures by company for 2007:

Company		2007 Estimated Construction Expenditures (in millions)
AEGCo	$	18
APCo		664
CSPCo		337
I&M		252
KPCo		71
OPCo		832
PSO		319
SWEPCo		537
TCC		241
TNC		143

In addition, AEGCo and CSPCo announced the purchase of gas-fired generating units for $325 million and $102 million, respectively.

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, weather, legal reviews and the ability to access capital.

Certain Registrant Subsidiaries entered into long-term contracts to acquire fuel for electric generation. The longest fuel contract extends to 2017 for APCo, 2015 for CSPCo, 2014 for I&M, 2009 for KPCo, 2021 for OPCo, 2007 for PSO and 2029 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release the Registrant Subsidiary from its obligations under certain conditions.

The Registrant Subsidiaries purchase materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. Management does not expect to incur penalty payments under these provisions that would materially affect results of operations, cash flows or financial condition.

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 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 December 31, 2006, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, with maturities ranging from March 2007 to June 2007.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides 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 Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of December 31, 2006, SWEPCo has collected approximately $29 million through a rider for final mine closure costs, which is recorded in Deferred Credits and Other on SWEPCo's Consolidated Balance Sheets.

SWEPCo is the only customer of Sabine. Sabine charges SWEPCo all its costs which are included in the cost of fuel and passed through SWEPCo's fuel clause.

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 December 31, 2006, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except TCC. TCC sale agreements include indemnifications with a maximum exposure of $443 million related to the sale price of its generation assets. See "Texas Plants – South Texas Project" section of Note 8. There are no material liabilities recorded for any indemnifications.

AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

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 December 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:

Company	Maximum Potential Loss (in millions)
APCo	$ 7
CSPCo	4
I&M	5
KPCo	2
OPCo	7
PSO	5
SWEPCo	6
TCC	6
TNC	3

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA, certain special interest groups and a number of states allege 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 alleged modifications occurred at our generating units over a twenty-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

Under the CAA, if a plant undertakes a major modification that 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 were 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 were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted 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. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. The Federal EPA also 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, if any, 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 March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the second quarter of 2007.

In 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, cash flows or financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims – Affecting AEP East Companies and AEP West Companies

In 2004, eight states and 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. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendant's power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. Management believes the actions are without merit and intends to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Registrant Subsidiaries currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2006, APCo and OPCo are each named as a Potentially Responsible Party (PRP) for one site and CSPCo and I&M are each named a PRP for two sites by the Federal EPA. There are nine additional sites for which APCo, CSPCo, I&M, KPCo, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M, SWEPCo, TCC and TNC have also been named potentially liable at two sites under state law. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

The Registrant Subsidiaries evaluate the potential liability for each Superfund site separately, but several general statements can be made regarding their potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, present estimates do not anticipate material cleanup costs for identified sites for which certain Registrant Subsidiaries have been declared PRPs. If significant cleanup costs were attributed to those Registrant Subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in electricity prices.

TEM Litigation – Affecting OPCo

Juniper Capital L.P. (Juniper) constructed and financed AEP's ownership interest in the nonregulated Plaquemine Cogeneration Facility (the Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP subleased the Facility to the Dow Chemical Company (Dow). AEP sold the Facility in November 2006.

Prior to the sale, Dow used a portion of the energy produced by the Facility and sold the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a twenty-year term. OPCo sold the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market until the sale of the Facility. With the sale of the Facility, OPCo terminated its purchase agreement with Dow.

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). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In September 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo 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 OPCo breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In August 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus prejudgment interest. Any eventual proceeds will be recorded as a gain when received.

In September 2005, TEM posted a $142 million letter of credit as security pending appeal of the judgment. Both parties filed Notices of Appeal with the United States Court of Appeals for the Second Circuit, which heard oral argument on the appeals in December 2006. Management cannot predict the ultimate outcome of this proceeding.

Coal Transportation Dispute – Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in 2004, 2005 and 2006. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In August 2006, PSO filed its response, to which BNSF filed its reply. Management continues to work toward mitigating the disputed amounts to the extent possible.

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 Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). 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 Nevada utilities. In 2001, the Nevada 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 complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

The following table shows the severance benefits expense recorded in 2005 (primarily in Other Operation and Maintenance) resulting from a company-wide staffing and budget review, including the allocation of approximately $19.2 million of severance benefits expense associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees, but received allocated expenses. Remaining accruals as of December 31, 2005, reflected primarily in Current Liabilities – Other, ranged from $8 thousand to $1.1 million, and were settled by June 30, 2006. Payments and accrual adjustments recorded during 2006 were immaterial.

Company	Year Ended December 31, 2005 (in millions)
AEGCo	$ 0.3
APCo	4.5
CSPCo	2.6
I&M	4.7
KPCo	1.1
OPCo	3.9
PSO	1.4
SWEPCo	1.8
TCC	4.3
TNC	1.3

8. ACQUISITIONS, DISPOSITIONS, ASSET IMPAIRMENTS AND ASSETS HELD FOR SALE

ACQUISITIONS

Acquisitions Anticipated Being Completed During the First Half of 2007

Darby Electric Generating Station – Affecting CSPCo

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the first half of 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station – Affecting AEGCo

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for approximately $325 million and the assumption of liabilities of approximately $2 million. The transaction is contingent on the receipt of various regulatory approvals and is expected to close in the second quarter of 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW.

2006

None

2005

Waterford Plant – Affecting CSPCo

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC, a subsidiary of PSEG, for the purchase of the Waterford Plant in Waterford, Ohio. The Waterford Plant is a natural gas, combined cycle power plant with a generating capacity of 821 MW. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company – Affecting CSPCo

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power Company (Monongahela Power), which includes approximately 29,000 customers. In August 2005, AEP agreed to terms of a transaction, which included the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of CSPCo's customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station – Affecting APCo

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of the Ceredo Generating Station located near Ceredo, West Virginia. The Ceredo Generating Station is a natural gas, simple cycle power plant with a generating capacity of 505 MW. This transaction was completed in December 2005 for $100 million.

2004

None

DISPOSITIONS

2006

None

2005

Texas Plants – South Texas Project – Affecting TCC

In February 2004, TCC signed an agreement to sell its 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, TCC entered into sales agreements with two of its nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on TCC's results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System which included all of the generation facilities owned by the Registrant Subsidiaries.

2004

Texas Plants – TCC Generation Assets

In relation to the implementation of the Texas Restructuring Legislation, TCC signed an agreement in March 2004 to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on TCC's 2004 results of operations.

ASSET IMPAIRMENTS

2006

None

2005

Conesville Units 1 and 2 – Affecting CSPCo

In the third quarter of 2005, following management's extensive review of the commercial viability of CSPCo's generation fleet, management committed to a plan to retire CSPCo's Conesville Units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville Units 1 and 2 were considered retired as of the third quarter of 2005.

CSPCo recognized a pretax charge of approximately $39 million in 2005 related to its decision to retire the units. The impairment amount is classified in Asset Impairments and Other Related Charges on CSPCo's 2005 Consolidated Statement of Income.

2004

None

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), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville (the nonaffiliated co-owners). By May 2004, TCC received notice from the nonaffiliated co-owners 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. Golden Spread challenged these agreements in State District Court in Dallas County. Golden Spread alleges that the Public Utilities Board of the City of Brownsville 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 in October 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas.

In May 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, which was denied. Golden Spread then appealed to the Supreme Court of Texas and on December 15, 2006, its Petition for review was denied. Various contract claims, between the parties, that were severed from the appeal on the right of first refusal are pending in the District Court of Dallas County.

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. The sale did not have a significant effect on TCC's results of operations nor does TCC expect the remaining litigation to have a significant effect on its results of operations.

TCC's assets related to the Oklaunion Power Station are classified in Assets Held for Sale – Texas Generation Plant on TCC's Consolidated Balance Sheets at December 31, 2006 and 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.

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

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

9. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored 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 life insurance benefits for retired employees.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FSP FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" in 2004. The Medicare subsidy reduced the SFAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. As a result, the tax-free subsidy reduced 2004's net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO. The following table provides the reduction in the net periodic postretirement cost for 2004:

Company	Postretirement Benefit Cost Reduction (in thousands)
APCo	$ 5,208
CSPCo	2,417
I&M	3,647
KPCo	690
OPCo	4,106
PSO	1,520
SWEPCo	1,571
TCC	1,849
TNC	770

In December 2006, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented SFAS 158. The effect of this standard on their financial statements was a pretax AOCI adjustment that was partially or fully offset by a SFAS 71 regulatory asset and as applicable a deferred income tax asset resulting in a net of tax AOCI equity reduction. The following table shows their amounts:

Company	Total Adjustment	Regulatory Asset	Deferred Income Tax	AOCI Equity Reduction
	(in thousands)			
APCo	$ 204,456	$ 124,080	$ 28,132	$ 52,244
CSPCo	133,980	94,924	13,670	25,386
I&M	111,040	101,673	3,278	6,089
KPCo	24,375	24,375	-	-
OPCo	191,229	92,729	34,475	64,025
PSO	73,203	73,203	-	-
SWEPCo	78,709	59,649	6,671	12,389
TCC	105,108	105,108	-	-
TNC	43,883	29,334	5,092	9,457

The following tables provide a reconciliation of the changes in the AEP plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2006, and their funded status as of December 31 for each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2006 and 2005

	Pension Plans		Other Postretirement Benefit Plans	
	2006	2005	2006	2005
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Service Cost	97	93	39	42
Interest Cost	231	228	102	107
Participant Contributions	-	-	21	20
Actuarial (Gain) Loss	(293)	191	(55)	(320)
Plan Amendments	2	-	-	-
Benefit Payments	(276)	(273)	(112)	(118)
Medicare Subsidy Accrued	-	-	(8)	-
Projected Obligation at December 31	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Actual Return on Plan Assets	470	224	127	70
Company Contributions	9	637	94	107
Participant Contributions	-	-	21	20
Benefit Payments	(276)	(273)	(112)	(118)
Fair Value of Plan Assets at December 31	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Funded Status				
Funded Status at December 31	$ 238	$ (204)	$ (516)	$ (659)
Unrecognized Net Transition Obligation	-	-	-	152
Unrecognized Prior Service Cost (Benefit)	-	(9)	-	5
Unrecognized Net Actuarial Loss	-	1,266	-	471
Net Asset (Liability) Recognized	$ 238	$ 1,053	$ (516)	$ (31)

Amounts Recognized on AEP's Balance Sheets as of December 31, 2006 and 2005

	Pension Plans		**Other Postretirement Benefit Plans**	
	2006	**2005**	**2006**	**2005**
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 320	$ 1,099	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	-	(5)	-
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(74)	(46)	(511)	(31)
Funded Status	238		(516)	
Regulatory Assets	582	N/A	293	N/A
Deferred Income Taxes	60	10	66	N/A
Additional Minimum Liability	N/A	(35)	N/A	N/A
Intangible Asset	N/A	6	N/A	N/A
Accumulated Other Comprehensive Income (Loss), Net of tax	112	19	123	N/A
Total	$ 992	$ 1,053	$ (34)	$ (31)

N/A = Not Applicable

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2006

Components	**Pension Plans**	**Other Postretirement Benefit Plans**
	(in millions)	
Net Actuarial Loss	$ 759	$ 354
Prior Service Cost (Credit)	(5)	4
Transition Obligation	-	124
Pretax AOCI	$ 754	$ 482
Recorded as		
Regulatory Assets	$ 582	$ 293
Deferred Income Taxes	60	66
Net of tax AOCI	112	123
Pretax AOCI	$ 754	$ 482

The Registrant Subsidiaries, where applicable, recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery.

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2006 and 2005, and the target allocation for 2007, by asset category, are as follows:

	Target Allocation	**Percentage of Plan Assets at Year End**	
	2007	**2006**	**2005**
Asset Category	**(in percentage)**		
Equity Securities	65	63	62
Real Estate	5	6	4
Debt Securities	28	26	25
Cash and Cash Equivalents	2	5	9
Total	100	100	100

The asset allocations for AEP's other postretirement benefit plans at the end of 2006 and 2005, and target allocation for 2007, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2007	2006	2005
Asset Category		(in percentage)	
Equity Securities	65	66	68
Debt Securities	33	32	30
Other	2	2	2
Total	100	100	100

AEP's investment strategy for the employee benefit trust funds is to use a diversified portfolio of investments to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. To minimize risk, our employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Our investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. Our investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies. Because of the $320 million contribution at the end of 2005 the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2006.

The value of the pension plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005. The qualified plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.3 billion in December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

AEP bases the determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation

	2006	2005
	(in millions)	
Qualified Pension Plans	$ 3,861	$ 4,053
Nonqualified Pension Plans	78	81
Total	$ 3,939	$ 4,134

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2006 and 2005 were as follows:

	Underfunded Pension Plans As of December 31, 2006	2005
	(in millions)	
Projected Benefit Obligation	$ 82	$ 84
Accumulated Benefit Obligation	$ 78	$ 81
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 78	$ 81

AEP made a contribution of $626 million in 2005 to meet the goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	Pension Plans 2006	Pension Plans 2005	Other Postretirement Benefit Plans 2006	Other Postretirement Benefit Plans 2005
	(in percentages)			
Discount Rate	5.75	5.50	5.85	5.65
Rate of Compensation Increase	5.90(a)	5.90(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2006, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2007 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 8	N/A
Additional Discretionary Contributions	-	$ 82

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.

N/A = Not Applicable

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to fund nonqualified benefit payments, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans' trust is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes and is provided for in agreements with state regulatory authorities.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for AEP's pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2007	$ 345	$ 113	$ (9)
2008	354	121	(10)
2009	361	130	(11)
2010	366	139	(11)
2011	367	149	(12)
Years 2012 to 2016, in Total	1,821	839	(77)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2006, 2005 and 2004:

	Pension Plans			Other Postretirement Benefit Plans		
	2006	2005	2004	2006	2005	2004
			(in millions)			
Service Cost	$ 97	$ 93	$ 86	$ 39	$ 42	$ 41
Interest Cost	231	228	228	102	107	117
Expected Return on Plan Assets	(335)	(314)	(292)	(94)	(92)	(81)
Amortization of Transition Obligation	-	-	2	27	27	28
Amortization of Prior Service Cost (Credit)	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	79	55	17	22	25	36
Net Periodic Benefit Cost	71	61	40	96	109	141
Capitalized Portion	(21)	(17)	(10)	(27)	(33)	(46)
Net Periodic Benefit Cost Recognized as Expense	$ 50	$ 44	$ 30	$ 69	$ 76	$ 95

Estimated amounts expected to be amortized to net periodic benefit costs from AEP's pretax accumulated other comprehensive income during 2007 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 52	$ 15
Prior Service Cost (Credit)	(1)	-
Transition Obligation	-	27
Total Estimated 2007 Pretax AOCI Amortization	$ 51	$ 42

Net Benefit Cost by Registrant

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiary for fiscal years 2006, 2005 and 2004:

	Pension Plans			Other Postretirement Benefit Plans		
Company	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
	(in thousands)					
APCo	$ 5,876	$ 7,391	$ 1,272	$ 17,953	$ 20,005	$ 25,847
CSPCo	820	2,143	(1,626)	7,222	8,202	11,050
I&M	9,319	9,463	4,460	11,805	13,524	17,259
KPCo	1,435	1,506	571	2,050	2,204	2,961
OPCo	3,307	4,825	(415)	13,582	15,442	20,975
PSO	3,912	295	2,795	6,352	6,989	8,449
SWEPCo	4,890	1,462	3,602	6,311	6,849	8,400
TCC	3,091	(880)	2,987	6,787	7,521	10,144
TNC	1,303	158	1,351	2,861	3,291	4,280

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	(in percentages)					
Discount Rate	5.50	5.50	6.25	5.65	5.80	6.25
Expected Return on Plan Assets	8.50	8.75	8.75	8.00	8.37	8.35
Rate of Compensation Increase	5.90	3.70	3.70	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2006 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates	2006	2005
Initial	8.0 %	9.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	193	(161)

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plans for substantially all employees who are not members of the United Mine Workers of America (UMWA). These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. The matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee.

The following table provides the cost for contributions to the retirement savings plans by the following Registrant Subsidiaries for fiscal years 2006, 2005 and 2004:

Company	2006	2005	2004
		(in thousands)	
APCo	$ 7,471	$ 6,780	$ 6,538
CSPCo	3,224	2,929	2,723
I&M	8,764	7,892	7,262
KPCo	1,313	1,166	1,030
OPCo	6,440	5,962	5,688
PSO	3,312	2,915	2,731
SWEPCo	4,284	3,935	3,571
TCC	3,104	2,452	2,544
TNC	1,075	1,022	1,126

UMWA Benefits

APCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by APCo and benefits are paid from its general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2006, 2005 and 2004.

10. NUCLEAR

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. A significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant results from its ownership. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range is caused by variables in assumptions. I&M recovers estimated Cook Plant decommissioning costs in its rates. The amount recovered in rates for decommissioning the Cook Plant was $30 million in 2006 and $27 million in 2005 and 2004. Decommissioning costs recovered from customers are deposited in external trusts.

I&M deposited an additional $4 million in 2006, 2005 and 2004 in its decommissioning trust for Cook Plant under funding provisions approved by regulatory commissions. At December 31, 2006, the total decommissioning trust fund balance for the Cook Plant was $974 million. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2006, fees and related interest of $247 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt and funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $274 million are recorded as part of Spent Nuclear Fuel and Decommissioning Trust on I&M's Consolidated Balance Sheet. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel at market value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the "Nuclear Trust Funds" section of Note 1, I&M records unrealized gains and losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of I&M's nuclear trust fund investments at December 31:

	2006			2005		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Gross Unrealized Losses
			(in millions)			
Cash	$ 24	$ -	$ -	$ 21	$ -	$ -
Debt Securities	750	18	(8)	691	7	(7)
Equity Securities	474	192	(4)	422	148	(3)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,248	$ 210	$ (12)	$ 1,134	$ 155	$ (10)

Proceeds from sales of I&M's nuclear trust fund investments were $631 million, $557 million and $863 million in 2006, 2005 and 2004, respectively. Purchases of I&M's nuclear trust fund investments were $692 million, $607 million and $901 million in 2006, 2005 and 2004, respectively.

Gross realized gains from the sales of I&M's nuclear trust fund investments were $7 million, $4 million and $10 million in 2006, 2005 and 2004, respectively. Gross realized losses including other-than-temporary impairments in 2006 from the sales of I&M's nuclear trust fund investments were $7 million, $16 million and $17 million in 2006, 2005 and 2004, respectively.

With the sale of STP in May 2005, TCC transferred the nuclear decommissioning liability and the related trust assets to the purchaser. Proceeds from sales of TCC's nuclear trust fund investments were $150 million and $87 million in 2005 and 2004, respectively. Purchases of TCC's nuclear trust fund investments were $154 million and $100 million in 2005 and 2004, respectively.

Gross realized gains from the sales of TCC's nuclear trust fund investments were $9 million and $3 million in 2005 and 2004, respectively. Gross realized losses from the sales of TCC's nuclear trust fund investments were $2 million and $1 million in 2005 and 2004, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2006 for I&M is as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 50
1 year – 5 years	188
5 years – 10 years	215
After 10 years	297
Total	$ 750

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. I&M's participation in this mutual insurer requires a contingent financial obligation of up to $38 million which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $300 million through commercially available insurance. The next level of liability coverage of up to $10.8 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition could be adversely affected.

11. 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, and TCC and TNC, which are primarily transmission and distribution businesses. 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 cost-based rates and regulatory oversight on the business process, cost structures and operating results.

12. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the influence that imperfections in marketplace transparency may cause pricing to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant Subsidiaries' accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Registrant Financial Statements. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the statements of income depending on the relevant facts and circumstances.

Depending on the exposure, the Registrant Subsidiaries designate a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), Registrant Subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) until the period the hedged item affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized immediately in earnings during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Fair Value Hedging Strategies

Certain Registrant Subsidiaries enter into interest rate derivative transactions in order to manage interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Registrant Subsidiaries record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on the statements of income. During 2006, 2005 and 2004, no Registrant Subsidiaries recognized hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

At times certain Registrant Subsidiaries are exposed to foreign currency exchange rate risks because they may purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, the Registrant Subsidiaries may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The accumulated gains or losses related to our foreign currency hedges, which are immaterial, are reclassified from Accumulated Other Comprehensive Income (Loss) into Operating Expenses over the same period as the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure.

Certain Registrant Subsidiaries enter into interest rate derivative transactions in order to manage interest rate risk exposure. Certain Registrant Subsidiaries enter into forward starting interest rate swap or treasury lock contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. Registrant Subsidiaries reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. During 2005 and 2006, certain Registrant Subsidiaries reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, certain Registrant Subsidiaries reclassified immaterial amounts to earnings because the original forecasted transaction did not occur within the originally specified time period.

Registrant Subsidiaries enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2006, 2005 and 2004, certain Registrant Subsidiaries recognized immaterial amounts in earnings related to hedge ineffectiveness.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2004, 2005 and 2006:

	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
Balance at December 31, 2003	$ (1,569)	$ 202	$ 222	$ 420	$ (103)
Effective portion of changes in fair value	(6,269)	2,304	(3,141)	918	2,830
Reclasses from AOCI to net income	(1,486)	(1,113)	(1,157)	(525)	(1,486)
Balance at December 31, 2004	(9,324)	1,393	(4,076)	813	1,241
Effective portion of changes in fair value	(4,515)	(71)	2,489	81	2,281
Reclasses from AOCI to net income	(2,582)	(2,181)	(1,880)	(1,088)	(2,767)
Balance at December 31, 2005	(16,421)	(859)	(3,467)	(194)	755
Effective portion of changes in fair value	10,365	3,438	(6,576)	1,496	6,899
Impact Due to Changes in SIA (a)	(442)	(261)	(267)	(106)	(337)
Reclasses from AOCI to net income	3,951	1,080	1,348	356	(55)
Balance at December 31, 2006	$ (2,547)	$ 3,398	$ (8,962)	$ 1,552	$ 7,262

	PSO	SWEPCo	TCC	TNC
		(in thousands)		
Balance at December 31, 2003	$ 156	$ 184	$ (1,828)	$ (601)
Effective portion of changes in fair value	713	(450)	866	373
Reclasses from AOCI to net income	(469)	(554)	1,619	513
Balance at December 31, 2004	400	(820)	657	285
Effective portion of changes in fair value	(1,168)	(4,817)	(635)	(290)
Reclasses from AOCI to net income	(344)	(215)	(246)	(106)
Balance at December 31, 2005	(1,112)	(5,852)	(224)	(111)
Effective portion of changes in fair value	(728)	(1,833)	-	(703)
Impact Due to Changes in SIA (a)	506	592	218	98
Reclasses from AOCI to net income	264	683	6	14
Balance at December 31, 2006	$ (1,070)	$ (6,410)	$ -	$ (702)

(a) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 4.

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2006 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is forty-two months.

Company	(in thousands)
APCo	$ 3,709
CSPCo	3,357
I&M	2,521
KPCo	1,340
OPCo	4,791
PSO	(183)
SWEPCo	(755)
TCC	-
TNC	-

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of significant financial instruments for Registrant Subsidiaries at December 31, 2006 and 2005 are summarized in the following tables.

	2006		2005	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
AEGCo				
Long-term Debt	$ 44,837	$ 45,928	$ 44,828	$ 45,216
APCo				
Long-term Debt	2,598,664	2,577,506	2,151,378	2,134,973
CSPCo				
Long-term Debt	1,197,322	1,211,176	1,196,920	1,232,553
I&M				
Long-term Debt	1,555,135	1,549,985	1,444,940	1,456,000
KPCo				
Long-term Debt	446,968	440,839	486,990	484,834
OPCo				
Long-term Debt	2,401,741	2,417,050	2,199,670	2,250,708
PSO				
Long-term Debt	669,998	670,531	571,071	568,998
SWEPCo				
Long-term Debt	729,006	718,902	744,641	744,915
TCC				
Long-term Debt	3,015,614	3,040,398	1,853,496	1,916,511
TNC				
Long-term Debt	276,936	277,842	276,845	281,047

13. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes before extraordinary loss and cumulative effect of accounting changes as reported are as follows:

Year Ended December 31, 2006	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Income Tax Expense (Credit):					
Current	$ 9,244	$ 88,750	$ 114,007	$ 70,231	$ 17,203
Deferred	(6,730)	17,225	(10,900)	13,626	2,596
Deferred Investment Tax Credits	(3,433)	(4,559)	(2,264)	(7,752)	(1,144)
Total Income Tax	$ (919)	$ 101,416	$ 100,843	$ 76,105	$ 18,655

Year Ended December 31, 2006	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Income Tax Expense (Credit):					
Current	$ 165,290	$ 40,690	$ 71,589	$ (680)	$ 5,751
Deferred	(43,997)	(23,672)	(23,667)	24,200	(227)
Deferred Investment Tax Credits	(2,969)	(1,031)	(4,225)	(870)	(1,270)
Total Income Tax	$ 118,324	$ 15,987	$ 43,697	$ 22,650	$ 4,254

Year Ended December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Income Tax Expense (Credit):					
Current	$ 5,089	$ (1,915)	$ 44,968	$ 62,082	$ 2,803
Deferred	(1,666)	72,763	19,209	26,873	10,555
Deferred Investment Tax Credits	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
Total Income Tax	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136

Year Ended December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Income Tax Expense (Credit):					
Current	$ 68,508	$ (14,510)	$ 44,156	$ 106,437	$ 24,426
Deferred	59,593	46,342	(4,942)	(91,387)	(4,578)
Deferred Investment Tax Credits	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
Total Income Tax	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577

Year Ended December 31, 2004	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Income Tax Expense (Credit):					
Current	$ 5,442	$ 37,689	$ 57,140	$ 84,639	$ (2,870)
Deferred	(2,219)	47,585	13,395	(5,548)	12,774
Deferred Investment Tax Credits	(3,339)	(163)	(2,864)	(7,476)	(1,233)
Total Income Tax	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671

Year Ended December 31, 2004	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Income Tax Expense (Credit):					
Current	$ 75,883	$ (12,434)	$ 26,271	$ 123,304	$ 19,565
Deferred	23,329	22,034	12,782	16,490	4,236
Deferred Investment Tax Credits	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
Total Income Tax	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509

Shown below is a reconciliation for each Registrant Subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

Year Ended December 31, 2006	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$ 10,914	$ 181,449	$ 185,579	$ 121,168	$ 35,035
Cumulative Effect of Accounting Changes	-	-	-	-	-
Income Taxes	(919)	101,416	100,843	76,105	18,655
Pretax Income	$ 9,995	$ 282,865	$ 286,422	$ 197,273	$ 53,690
Income Tax on Pretax Income at Statutory Rate (35%)	$ 3,498	$ 99,003	$ 100,248	$ 69,046	$ 18,791
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	120	10,325	1,395	20,834	1,669
Nuclear Fuel Disposal Costs	-	-	-	(5,538)	-
Allowance for Funds Used During Construction	(1,075)	(7,379)	(789)	(5,149)	(606)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	(17)	(3,339)	(544)	(5,968)	(1,361)
Investment Tax Credits, Net	(3,433)	(4,559)	(2,264)	(7,752)	(1,144)
State and Local Income Taxes	634	12,678	(53)	4,559	1,070
Other	(1,020)	(5,313)	2,850	5,676	236
Total Income Taxes	$ (919)	$ 101,416	$ 100,843	$ 76,105	$ 18,655
Effective Income Tax Rate	N.M.	35.9%	35.2%	38.6%	34.7%

N.M. = Not Meaningful

Year Ended December 31, 2006	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income	$ 228,643	$ 36,860	$ 91,723	$ 41,569	$ 14,943
Cumulative Effect of Accounting Changes	-	-	-	-	-
Extraordinary Loss	-	-	-	-	-
Income Taxes	118,324	15,987	43,697	22,650	4,254
Pretax Income	$ 346,967	$ 52,847	$ 135,420	$ 64,219	$ 19,197
Income Tax on Pretax Income at Statutory Rate (35%)	$ 121,438	$ 18,496	$ 47,397	$ 22,477	$ 6,719
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,397	(593)	(85)	(453)	(500)
Depletion	-	-	(3,150)	-	-
Investment Tax Credits, Net	(2,969)	(1,031)	(4,225)	(870)	(1,270)
State and Local Income Taxes	270	260	3,764	3,782	(759)
Other	(4,812)	(1,145)	(4)	(2,286)	64
Total Income Taxes	$ 118,324	$ 15,987	$ 43,697	$ 22,650	$ 4,254
Effective Income Tax Rate	34.1%	30.3%	32.3%	35.3%	22.2%

Year Ended December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$ 8,695	$ 133,576	$ 136,960	$ 146,852	$ 20,809
Cumulative Effect of Accounting Changes	-	2,256	839	-	-
Income Taxes	(109)	66,189	61,460	81,230	12,136
Pretax Income	$ 8,586	$ 202,021	$ 199,259	$ 228,082	$ 32,945
Income Tax on Pretax Income at Statutory Rate (35%)	$ 3,005	$ 70,707	$ 69,741	$ 79,829	$ 11,531
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	757	11,257	1,614	19,492	1,644
Nuclear Fuel Disposal Costs	-	-	-	(3,413)	-
Allowance for Funds Used During Construction	(1,097)	(4,786)	(679)	(3,819)	(614)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(4,275)	(357)	(5,476)	(995)
Investment Tax Credits, Net	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
State and Local Income Taxes	723	2,223	448	6,598	778
Other	(339)	(4,278)	(6,590)	(4,653)	1,014
Total Income Taxes	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136
Effective Income Tax Rate	N.M.	32.8%	30.8%	35.6%	36.8%

N.M. = Not Meaningful

Year Ended December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income (Loss)	$ 245,844	$ 57,893	$ 73,938	$ (173,779)	$ 33,004
Extraordinary Loss	-	-	-	224,551	-
Cumulative Effect of Accounting Changes	4,575	-	1,252	-	8,472
Income Taxes	124,978	30,485	34,922	12,441	18,577
Pretax Income	$ 375,397	$ 88,378	$ 110,112	$ 63,213	$ 60,053
Income Tax on Pretax Income at Statutory Rate (35%)	$ 131,389	$ 30,932	$ 38,539	$ 22,125	$ 21,019
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	5,195	(775)	(211)	(519)	(513)
Depletion	-	-	(3,150)	-	-
Investment Tax Credits, Net	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
State and Local Income Taxes	5,437	(1,387)	1,831	300	718
Other	(13,920)	3,062	2,205	(6,856)(a)	(1,376)
Total Income Taxes	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577
Effective Income Tax Rate	33.3%	34.5%	31.7%	19.7%	30.9%

(a) Includes $(3,900) of consolidated tax savings from parent.

Year Ended December 31, 2004	AEGCo		APCo		CSPCo		I&M		KPCo	
					(in thousands)					
Net Income	$	7,842	$	153,115	$	140,258	$	133,222	$	25,905
Income Taxes		(116)		85,111		67,671		71,615		8,671
Pretax Income	$	7,726	$	238,226	$	207,929	$	204,837	$	34,576
Income Tax on Pretax Income at Statutory Rate (35%)	$	2,704	$	83,379	$	72,775	$	71,693	$	12,102
Increase (Decrease) in Income Tax resulting from the following items:										
Depreciation		808		10,719		2,570		19,023		1,466
Nuclear Fuel Disposal Costs		-		-		-		(3,338)		-
Allowance for Funds Used During Construction		(1,060)		(3,948)		(515)		(3,160)		(603)
Rockport Plant Unit 2 Investment Tax Credit		374		-		-		397		-
Removal Costs		-		(1,632)		(336)		(2,974)		(1,497)
Investment Tax Credits, Net		(3,339)		(163)		(2,864)		(7,476)		(1,233)
State and Local Income Taxes		933		6,629		159		7,102		(197)
Other		(536)		(9,873)		(4,118)		(9,652)		(1,367)
Total Income Taxes	$	(116)	$	85,111	$	67,671	$	71,615	$	8,671
Effective Income Tax Rate		N.M.		35.7%		32.5%		35.0%		25.1%

N.M. = Not Meaningful

Year Ended December 31, 2004	OPCo		PSO		SWEPCo		TCC		TNC	
					(in thousands)					
Net Income	$	210,116	$	37,542	$	89,457	$	174,122	$	47,659
Extraordinary Loss		-		-		-		120,534		-
Income Taxes		96,110		7,809		34,727		135,058		22,509
Pretax Income	$	306,226	$	45,351	$	124,184	$	429,714	$	70,168
Income Tax on Pretax Income at Statutory Rate (35%)	$	107,179	$	15,873	$	43,464	$	150,400	$	24,559
Increase (Decrease) in Income Tax resulting from the following items:										
Depreciation		4,977		(937)		(1,622)		(812)		(739)
Depletion		-		-		(2,100)		-		-
Investment Tax Credits, Net		(3,102)		(1,791)		(4,326)		(4,736)		(1,292)
State and Local Income Taxes		305		1,882		4,736		543		2,762
Other		(13,249)		(7,218)		(5,425)		(10,337)		(2,781)
Total Income Taxes	$	96,110	$	7,809	$	34,727	$	135,058	$	22,509
Effective Income Tax Rate		31.4%		17.2%		28.0%		31.4%		32.1%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

As of December 31, 2006	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Deferred Tax Assets	$ 56,758	$ 359,085	$ 117,884	$ 696,709	$ 38,454
Deferred Tax Liabilities	(76,507)	(1,316,314)	(593,772)	(1,031,709)	(280,587)
Net Deferred Tax Liabilities	$ (19,749)	$ (957,229)	$ (475,888)	$ (335,000)	$ (242,133)
Property Related Temporary Differences	$ (51,683)	$ (742,711)	$ (381,832)	$ (1,550)	$ (180,662)
Amounts Due From Customers For Future Federal Income Taxes	4,036	(101,554)	(5,745)	(23,938)	(24,888)
Deferred State Income Taxes	(2,060)	(97,887)	(8,559)	(42,329)	(29,331)
Transition Regulatory Assets	-	(5,942)	(34,179)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	29,503	11,840	8,104	(836)
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	30,068	-	-	20,670	-
Accrued Nuclear Decommissioning Expense	-	-	-	(246,533)	-
Deferred Fuel and Purchased Power	-	7,117	(39)	(146)	(410)
Accrued Pensions	-	(17,769)	(16,161)	(7,618)	(1,665)
Nuclear Fuel	-	-	-	(16,403)	-
All Other, Net	(110)	(27,986)	(41,213)	(25,257)	(4,341)
Net Deferred Tax Liabilities	$ (19,749)	$ (957,229)	$ (475,888)	$ (335,000)	$ (242,133)

As of December 31, 2006	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Deferred Tax Assets	$ 215,890	$ 107,723	$ 109,860	$ 235,109	$ 44,915
Deferred Tax Liabilities	(1,127,111)	(521,920)	(484,408)	(1,269,232)	(168,963)
Net Deferred Tax Liabilities	$ (911,221)	$ (414,197)	$ (374,548)	$ (1,034,123)	$ (124,048)
Property Related Temporary Differences	$ (789,303)	$ (351,461)	$ (319,240)	$ (251,645)	$ (124,197)
Amounts Due From Customers For Future Federal Income Taxes	(51,673)	3,747	(1,382)	6,477	3,392
Deferred State Income Taxes	(33,053)	(55,256)	(38,073)	(2,248)	(1,471)
Transition Regulatory Assets	(25,273)	-	-	19,239	-
Accrued Nuclear Decommissioning Expense	-	-	-	(928)	-
Deferred Income Taxes on Other Comprehensive Loss	30,565	576	10,337	-	5,470
Deferred Fuel and Purchased Power	-	(2,644)	(6,501)	31,774	3,525
Accrued Pensions	(30,668)	(14,182)	(11,676)	(15,494)	(10,131)
Provision for Refund	2,690	67	415	50	77
Regulatory Assets	(34,821)	(30,392)	(21,293)	(15,795)	(13,009)
Securitized Transition Assets	-	-	-	(809,065)	-
All Other, Net	20,315	35,348	12,865	3,512	12,296
Net Deferred Tax Liabilities	$ (911,221)	$ (414,197)	$ (374,548)	$ (1,034,123)	$ (124,048)

As of December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Deferred Tax Assets	$ 61,315	$ 221,910	$ 76,785	$ 614,838	$ 26,806
Deferred Tax Liabilities	(84,932)	(1,174,407)	(575,017)	(950,102)	(261,525)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)
Property Related Temporary Differences	$ (56,297)	$ (695,698)	$ (391,117)	$ (42,401)	$ (175,512)
Amounts Due From Customers For Future Federal Income Taxes	5,711	(93,171)	(6,053)	(28,714)	(24,720)
Deferred State Income Taxes	(3,987)	(108,455)	(9,409)	(36,352)	(25,950)
Transition Regulatory Assets	-	(7,428)	(50,719)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	8,944	473	1,922	120
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	32,018	-	-	21,303	-
Accrued Nuclear Decommissioning Expense	-	-	-	(214,126)	-
Deferred Fuel and Purchased Power	-	7,471	(39)	(1,200)	(1,080)
Accrued Pensions	-	(48,649)	(40,460)	(28,443)	(6,488)
Nuclear Fuel	-	-	-	(8,040)	-
All Other, Net	(1,062)	(15,511)	(908)	787	(1,089)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)

As of December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Deferred Tax Assets	$ 138,836	$ 50,570	$ 67,226	$ 146,877	$ 37,158
Deferred Tax Liabilities	(1,126,222)	(486,952)	(476,739)	(1,195,249)	(169,493)
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)
Property Related Temporary Differences	$ (789,885)	$ (336,743)	$ (321,810)	$ (240,361)	$ (121,192)
Amounts Due From Customers For Future Federal Income Taxes	(51,780)	4,231	(961)	7,216	3,892
Deferred State Income Taxes	(41,366)	(59,574)	(45,218)	(43,427)	(7,316)
Transition Regulatory Assets	(49,505)	-	14	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,983)	-
Deferred Income Taxes on Other Comprehensive Loss	(406)	681	3,300	620	271
Deferred Fuel and Purchased Power	-	(37,984)	(26,449)	(1,738)	(8,554)
Accrued Pensions	(52,450)	(32,387)	(29,041)	(41,894)	(17,698)
Provision for Refund	-	67	843	40,111	11,671
Regulatory Assets	(4,981)	(3,665)	(496)	(464,080)	(2,915)
Securitized Transition Assets	-	-	-	(231,587)	-
All Other, Net	2,987	28,992	10,305	(3,173)	9,506
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to such losses in determining their current tax expense. The tax benefit of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The IRS and other taxing authorities routinely examine the Registrant Subsidiaries tax returns. Management believes that the Registrant Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. Registrant Subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for years prior to1997. Management has reached a negotiated settlement of all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipates payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2006, Registrant Subsidiaries have total provisions for uncertain tax positions of approximately $16 million, excluding AEGCo. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of Integrated Gasification Combined Cycle (IGCC) plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. AEP will continue to pursue credits for the next round of credits in 2009.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over eighty-four months in lieu of taking a depreciation deduction over 20-years. This act also allows for the transfer ("poured-over") of funds held in nonqualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the nonqualified funds are poured-over; the funds are poured-over during the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for nonqualified funds. The tax law changes discussed in this paragraph have not materially affected AEP's results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. The application of these tax acts has not materially affected our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, AEP reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows:

Company	Other Regulatory Liabilities (a)	SFAS 109 Regulatory Asset, Net (b)	State Income Tax Expense (c)	Deferred State Income Tax Liabilities (d)
	(in thousands)			
APCo	$ -	$ 10,945	$ 2,769	$ 13,714
CSPCo	15,104	-	-	15,104
I&M	-	5,195	-	5,195
KPCo	-	3,648	-	3,648
OPCo	41,864	-	-	41,864
PSO	-	-	706	706
SWEPCo	-	582	119	701
TCC	-	1,156	365	1,521
TNC	-	120	75	195

(a) The reversal of deferred state income taxes for the Ohio companies was recorded as a regulatory liability pending rate-making treatment in Ohio. See "Ormet" section of Note 4.
(b) Deferred state income tax adjustments related to those companies in which state income taxes flow through for rate-making purposes reduced the regulatory asset associated with the deferred state income tax liabilities.
(c) These amounts were recorded as a reduction to Income Tax Expense.
(d) Total deferred state income tax liabilities that reversed during 2005 related to Ohio law change.

In November 2006, the PUCO ordered OPCo and CSPCo to amortize $41,864 and $15,104, respectively, to income as an offset to power supply contract losses incurred by Ohio Power and Columbus Southern Power for sales to Ormet.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2006 and 2005 were approximately $2 million and $1 million for CSPCo and $2 million and $1 million for OPCo, respectively.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, management reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 the following adjustments were recorded:

Company	Decrease in SFAS 109 Regulatory Asset, Net	Decrease in State Income Tax Expense	Decrease in Deferred State Income Tax Liabilities
		(in thousands)	
TCC	$ 36,315	$ -	$ 36,315
TNC	4,801	1,265	6,066
PSO	-	3,273	3,273
SWEPCo	4,438	501	4,939

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. Management believes the application of this act will not materially affect the Registrant Subsidiaries' results of operations, cash flows, or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect the Registrant Subsidiaries' results of operations, cash flows, or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provides a new alternative formula for deterring the research credit. The application of TRHCA 2006 is not expected to materially affect the Registrant Subsidiaries' results of operations, cash flows or financial condition.

14. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2006	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 72,205	$ 12,657	$ 5,093	$ 97,750	$ 2,079
Amortization of Capital Leases	310	5,825	3,221	6,533	1,207
Interest on Capital Leases	702	873	429	2,807	116
Total Lease Rental Costs	$ 73,217	$ 19,355	$ 8,743	$ 107,090	$ 3,402

Year Ended December 31, 2006	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Lease Expense on Operating Leases	$ 20,985	$ 6,901	$ 6,808	$ 6,091	$ 2,812
Amortization of Capital Leases	7,946	1,155	6,504	1,024	397
Interest on Capital Leases	2,155	232	3,689	223	82
Total Lease Rental Costs	$ 31,086	$ 8,288	$ 17,001	$ 7,338	$ 3,291

Year Ended December 31, 2005	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 72,301	$ 8,539	$ 6,194	$ 93,993	$ 1,735
Amortization of Capital Leases	284	6,273	3,313	6,681	1,519
Interest on Capital Leases	709	449	540	2,442	34
Total Lease Rental Costs	$ 73,294	$ 15,261	$ 10,047	$ 103,116	$ 3,288

Year Ended December 31, 2005	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Lease Expense on Operating Leases	$ 10,528	$ 5,658	$ 5,867	$ 5,594	$ 2,275
Amortization of Capital Leases	7,940	668	6,200	478	249
Interest on Capital Leases	2,275	93	2,738	60	34
Total Lease Rental Costs	$ 20,743	$ 6,419	$ 14,805	$ 6,132	$ 2,558

Year Ended December 31, 2004	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 69,974	$ 6,832	$ 5,313	$ 107,637	$ 1,416
Amortization of Capital Leases	92	7,906	3,933	6,825	1,605
Interest on Capital Leases	7	1,260	705	1,403	258
Total Lease Rental Costs	$ 70,073	$ 15,998	$ 9,951	$ 115,865	$ 3,279

Year Ended December 31, 2004	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Lease Expense on Operating Leases	$ 14,390	$ 3,697	$ 4,877	$ 3,949	$ 1,458
Amortization of Capital Leases	8,232	520	3,543	437	216
Interest on Capital Leases	2,259	53	2,054	66	27
Total Lease Rental Costs	$ 24,881	$ 4,270	$ 10,474	$ 4,452	$ 1,701

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries' balance sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on the Registrant Subsidiaries' balance sheets.

As of December 31, 2006	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,272	$ 1,264	$ 7,104	$ 18,480	$ 436
Distribution	-	-	-	14,589	-
Other	428	30,578	13,009	40,227	6,723
Construction Work in Progress	-	-	-	-	-
Total Property, Plant and Equipment	12,700	31,842	20,113	73,296	7,159
Accumulated Amortization	699	20,011	11,660	30,240	4,512
Net Property, Plant and Equipment Under Capital Leases	$ 12,001	$ 11,831	$ 8,453	$ 43,056	$ 2,647
Obligations Under Capital Leases:					
Noncurrent Liability	$ 11,675	$ 7,699	$ 5,731	$ 27,073	$ 1,493
Liability Due Within One Year	326	4,160	2,741	15,983	1,154
Total Obligations Under Capital Leases	$ 12,001	$ 11,859	$ 8,472	$ 43,056	$ 2,647

As of December 31, 2006	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Production	$ 39,807	$ -	$ 14,270	$ -	$ -
Distribution	-	-	-	-	-
Other	31,590	6,387	82,209	5,480	2,110
Construction Work in Progress	-	-	29,777	-	-
Total Property, Plant and Equipment	71,397	6,387	126,256	5,480	2,110
Accumulated Amortization	38,102	1,571	41,894	1,306	467
Net Property, Plant and Equipment Under Capital Leases	$ 33,295	$ 4,816	$ 84,362	$ 4,174	$ 1,643
Obligations Under Capital Leases:					
Noncurrent Liability	$ 25,996	$ 3,332	$ 72,061	$ 2,739	$ 1,137
Liability Due Within One Year	8,970	1,484	12,654	1,358	506
Total Obligations Under Capital Leases	$ 34,966	$ 4,816	$ 84,715	$ 4,097	$ 1,643

As of December 31, 2005	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,316	$ 1,275	$ 7,104	$ 18,964	$ 436
Distribution	-	-	-	14,589	-
Other	349	36,792	16,059	38,568	9,128
Total Property, Plant and Equipment	12,665	38,067	23,163	72,121	9,564
Accumulated Amortization	438	23,185	13,609	28,145	6,396
Net Property, Plant and Equipment Under Capital Leases	$ 12,227	$ 14,882	$ 9,554	$ 43,976	$ 3,168
Obligations Under Capital Leases:					
Noncurrent Liability	$ 11,930	$ 9,292	$ 6,545	$ 38,645	$ 2,030
Liability Due Within One Year	297	5,600	3,031	5,331	1,138
Total Obligations Under Capital Leases	$ 12,227	$ 14,892	$ 9,576	$ 43,976	$ 3,168

As of December 31, 2005	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases:					
Production	$ 40,554	$ -	$ 14,270	$ -	$ -
Distribution	-	-	-	-	-
Other	37,867	3,378	65,014	2,072	1,045
Total Property, Plant and Equipment	78,421	3,378	79,284	2,072	1,045
Accumulated Amortization	39,912	844	36,803	694	321
Net Property, Plant and Equipment Under Capital Leases	$ 38,509	$ 2,534	$ 42,481	$ 1,378	$ 724
Obligations Under Capital Leases:					
Noncurrent Liability	$ 30,750	$ 1,778	$ 37,055	$ 888	$ 506
Liability Due Within One Year	9,174	756	5,490	490	218
Total Obligations Under Capital Leases	$ 39,924	$ 2,534	$ 42,545	$ 1,378	$ 724

Future minimum lease payments consisted of the following at December 31, 2006:

Capital Leases	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
2007	$ 1,011	$ 4,793	$ 3,180	$ 17,135	$ 1,232
2008	1,001	4,268	2,931	7,416	809
2009	988	2,094	1,830	5,687	395
2010	970	1,557	1,276	2,819	260
2011	935	219	118	1,875	97
Later Years	16,101	311	68	19,205	83
Total Future Minimum Lease Payments	21,006	13,242	9,403	54,137	2,876
Less Estimated Interest Element	9,005	1,383	931	11,081	229
Estimated Present Value of Future Minimum Lease Payments	$ 12,001	$ 11,859	$ 8,472	$ 43,056	$ 2,647

Capital Leases	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
2007	$ 9,277	$ 1,728	$ 13,528	$ 1,574	$ 593
2008	7,173	1,540	13,855	1,488	565
2009	5,069	1,172	13,610	1,009	399
2010	4,046	722	9,380	394	206
2011	1,822	153	8,134	62	64
Later Years	20,885	62	61,201	15	-
Total Future Minimum Lease Payments	48,272	5,377	119,708	4,542	1,827
Less Estimated Interest Element	13,306	561	34,993	445	184
Estimated Present Value of Future Minimum Lease Payments	$ 34,966	$ 4,816	$ 84,715	$ 4,097	$ 1,643

Noncancelable Operating Leases	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
2007	$ 77,338	$ 12,436	$ 5,288	$ 98,894	$ 2,069
2008	77,334	11,020	4,665	98,311	1,693
2009	77,331	8,788	4,175	96,614	1,459
2010	77,178	7,685	3,379	93,040	1,348
2011	76,731	5,832	2,286	91,809	996
Later Years	814,478	14,725	4,500	873,750	2,334
Total Future Minimum Lease Payments	$ 1,200,390	$ 60,486	$ 24,293	$ 1,352,418	$ 9,899

Noncancelable Operating Leases	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
2007	$ 21,269	$ 6,779	$ 7,373	$ 6,243	$ 2,685
2008	19,287	4,730	6,665	5,165	2,444
2009	18,107	4,052	5,614	4,557	2,449
2010	16,576	4,208	3,935	4,363	2,061
2011	15,070	2,475	2,813	2,227	1,097
Later Years	71,018	5,834	6,102	3,086	1,974
Total Future Minimum Lease Payments	$ 161,327	$ 28,078	$ 32,502	$ 25,641	$ 12,710

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale and leaseback transaction for each respective company as of December 31, 2006 are as follows:

	AEGCo	I&M
	(in millions)	
2007	$ 74	$ 74
2008	74	74
2009	74	74
2010	74	74
2011	74	74
Later Years	812	812
Total Future Minimum Lease Payments	$ 1,182	$ 1,182

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $51 million electric dragline for Sabine's mining operations. The initial capital outlay for the dragline was $26 million with an additional estimated $25 million of transportation, assembly and upgrade costs to be incurred prior to the completion date of mid-2008. These additional costs will be added to SWEPCo's consolidated lease assets and capital lease obligations as they are incurred. Sabine will pay interim rent on a quarterly basis starting in March 2007 and continue through the completion date of mid-2008. Once the dragline is fully assembled, Sabine will pay capital and interest payments on the outstanding lease obligation. At December 31, 2006, the capital lease asset is included in Construction Work in Progress and the capital lease obligation is included in Noncurrent Liabilities – Deferred Credits and Other on SWEPCo's 2006 Consolidated Balance Sheet. SWEPCo calculated future payments using both interim rent prior to completion and capital and interest from completion until the maturity of the lease solely using the initial capital outlay of $26 million.

15. FINANCING ACTIVITIES

Preferred Stock

Company	Par Value	Authorized Shares	Shares Outstanding at December 31, 2006	Call Price at December 31, 2006 (a)	Series	Redemption	December 31, 2006	December 31, 2005
							(in thousands)	
APCo	$ 0(b)	8,000,000	177,634	$ 110.00	4.50%	Any time	$ 17,763	$ 17,784
CSPCo	25	7,000,000	-	-	-	-	-	-
CSPCo	100	2,500,000	-	-	-	-	-	-
I&M	25	11,200,000	-	-	-	-	-	-
I&M	100	(c)	55,357	106.125	4.125%	Any time	5,535	5,537
I&M	100	(c)	14,412	102.00	4.56%	Any time	1,441	1,441
I&M	100	(c)	11,055	102.728	4.12%	Any time	1,106	1,106
OPCo	25	4,000,000	-	-	-	-	-	-
OPCo	100	(d)	14,595	103.00	4.08%	Any time	1,460	1,460
OPCo	100	(d)	22,824	103.20	4.20%	Any time	2,282	2,282
OPCo	100	(d)	31,512	104.00	4.40%	Any time	3,151	3,151
OPCo	100	(d)	97,373	110.00	4.50%	Any time	9,737	9,746
PSO	100	(e)	44,548	105.75	4.00%	Any time	4,455	4,455
PSO	100	(e)	8,069	103.19	4.24%	Any time	807	807
SWEPCo	100	(f)	7,386	103.90	4.28%	Any time	740	740
SWEPCo	100	(f)	1,907	102.75	4.65%	Any time	190	190
SWEPCo	100	(f)	37,673	109.00	5.00%	Any time	3,767	3,770
TCC	100	(g)	41,912	105.75	4.00%	Any time	4,191	4,192
TCC	100	(g)	17,301	103.75	4.20%	Any time	1,730	1,748
TNC	100	810,000	23,486	107.00	4.40%	Any time	2,349	2,357

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Stated value is $100 per share.
(c) I&M has 2,250,000 authorized $100 par value per share shares in total.
(d) OPCo has 3,762,403 authorized $100 par value per share shares in total.
(e) PSO has 700,000 authorized shares in total.
(f) SWEPCo has 1,860,000 authorized shares in total.
(g) TCC has 3,035,000 authorized shares in total.

Company	Series	Number of Shares Redeemed for the Year Ended December 31, 2006	2005	2004
APCo	4.50%	202	-	3
APCo	5.90%	-	-	22,100
APCo	5.92%	-	-	31,500
I&M	4.12%	12	-	175
I&M	5.90%	-	132,000	20,000
I&M	6.25%	-	192,500	-
I&M	6.30%	-	132,450	-
I&M	6.875%	-	157,500	-
OPCo	4.50%	89	20	41
OPCo	5.90%	-	50,000	22,500
PSO	4.00%	-	-	50
SWEPCo	5.00%	30	-	-
TCC	4.00%	10	-	5
TCC	4.20%	175	-	-
TNC	4.40%	80	-	4

Long-term Debt

There are certain limitations on establishing liens against the Registrant Subsidiaries' assets under their respective indentures. None of the long-term debt obligations of the Registrant Subsidiaries have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2006 and 2005:

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
AEGCo				(in thousands)	
Pollution Control Bonds, City of Rockport, Series 1995 A and B (a) (b)	2025	4.15%	4.05%	$ 45,000	$ 45,000
Unamortized Premium (Discount)				(163)	(172)
Total Pollution Control Bonds - AEGCo				44,837	44,828
Total AEGCo Long-term Debt				44,837	44,828
Less: Long-term Debt Due Within One Year				-	44,828
Long-Term Debt				$ 44,837	$ -
APCo					
Pollution Control Bonds, Russell Co., Series I (a)	2007	-	2.70%	$ -	$ 17,500
Pollution Control Bonds, Putnam Co., Series E (a)	2019	-	2.80%	-	30,000
Pollution Control Bonds, Putnam Co., Series E (a)	2019	3.50%	-	30,000	-
Pollution Control Bonds, Putnam Co., Series F (a)	2019	3.60%	3.10%	40,000	40,000
Pollution Control Bonds, Russell Co., Series J (a)	2021	3.70%	-	17,500	-
Pollution Control Bonds, Russell Co., Series H (a)	2021	5.00%	5.00%	19,500	19,500
Pollution Control Bonds, Mason Co., Series L (a)	2022	5.50%	5.50%	100,000	100,000
Pollution Control Bonds, Mason Co., Series K (a)	2024	6.05%	6.05%	30,000	30,000
Pollution Control Bonds, West Virginia Econ. Dev. Auth, Series 2006 A (a)	2036	3.70%	-	50,275	-
Unamortized Premium (Discount)				(215)	(229)
Total Pollution Control Bonds - APCo				287,060	236,771
Senior Unsecured Notes, Series F	2007	4.3148%	4.3148%	200,000	200,000
Senior Unsecured Floating Rate Notes, Series C	2007	5.6938%	4.85%	125,000	125,000
Senior Unsecured Notes, Series G	2008	3.60%	3.60%	200,000	200,000
Senior Unsecured Notes, Series C	2009	6.60%	6.60%	150,000	150,000
Senior Unsecured Notes, Series J	2010	4.40%	4.40%	150,000	150,000
Senior Unsecured Notes, Series M	2011	5.55%	-	250,000	-
Senior Unsecured Notes, Series I	2015	4.95%	4.95%	200,000	200,000
Senior Unsecured Notes, Series K	2017	5.00%	5.00%	250,000	250,000
Senior Unsecured Notes, Series H	2033	5.95%	5.95%	200,000	200,000
Senior Unsecured Notes, Series L	2035	5.80%	5.80%	250,000	250,000
Senior Unsecured Notes, Series N	2036	6.375%	-	250,000	-
MTM of Fair Value Hedge				(1,171)	(1,360)
Unamortized Premium (Discount)				(14,718)	(11,524)
Total Senior Unsecured Notes - APCo				2,209,111	1,712,116
First Mortgage Bonds, 6.80% Series (d)	2006	-	6.80%	-	100,000
Unamortized Premium (Discount)				-	(13)
Total First Mortgage Bonds – APCo				-	99,987
Notes Payable – Affiliated	2010	4.708%	4.708%	100,000	100,000
Total Notes Payable – Affiliated - APCo				100,000	100,000
Other Long-term Debt	2026	13.718%	13.718%	2,493	2,504
Total Other Long-term Debt - APCo				2,493	2,504
Total APCo Long-term Debt				2,598,664	2,151,378
Less: Long-term Debt Due Within One Year				324,191	146,999
Long-term Debt				$ 2,274,473	$ 2,004,379

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
CSPCo				**(in thousands)**	
Pollution Control Bonds, State of Ohio Air Quality Series 2005 D (a)	2038	3.53%	3.20%	$ 48,550	$ 48,550
Pollution Control Bonds, State of Ohio Air Quality Series 2005 C (a)	2038	3.75%	3.35%	43,695	43,695
Unamortized Premium (Discount)				(158)	(163)
Total Pollution Control Bonds – CSPCo				92,087	92,082
Senior Unsecured Medium Term Notes, Series A	2008	6.51%	6.51%	52,000	52,000
Senior Unsecured Medium Term Notes, Series B	2008	6.55%	6.55%	60,000	60,000
Senior Unsecured Notes, Series E	2010	4.40%	4.40%	150,000	150,000
Senior Unsecured Notes, Series C	2013	5.50%	5.50%	250,000	250,000
Senior Unsecured Notes, Series B	2033	6.60%	6.60%	250,000	250,000
Senior Unsecured Notes, Series F	2035	5.85%	5.85%	250,000	250,000
Unamortized Premium (Discount)				(6,765)	(7,162)
Total Senior Unsecured Notes – CSPCo				1,005,235	1,004,838
Notes Payable – Affiliated	2010	4.64%	4.64%	100,000	100,000
Total Notes Payable – Affiliated – CSPCo				100,000	100,000
Total CSPCo Long-term Debt				1,197,322	1,196,920
Less: Long-term Debt Due Within One Year				-	-
Long-Term Debt				$ 1,197,322	$ 1,196,920
I&M					
Pollution Control Bonds, City of Sullivan, Series D (a)	2009	3.70%	3.229%	$ 45,000	$ 45,000
Pollution Control Bonds, City of Lawrenceburg, Series F (a)	2019	-	2.625%	-	25,000
Pollution Control Bonds, City of Lawrenceburg, Series F (a)	2019	3.55%	-	25,000	-
Pollution Control Bonds, City of Lawrenceburg, Series G (a)	2021	3.50%	3.20%	52,000	52,000
Pollution Control Bonds, City of Rockport, Series C (a)	2025	-	2.625%	-	40,000
Pollution Control Bonds, City of Rockport, Series C (a)	2025	3.74%	-	40,000	-
Pollution Control Bonds, City of Rockport, Series B (a)	2025	3.60%	3.20%	50,000	50,000
Pollution Control Bonds, City of Rockport, Series 2002A (a) (c)	2025	4.90%	4.90%	50,000	50,000
Pollution Control Bonds, City of Rockport, Series 1995A (a)	2025	-	6.55%	-	50,000
Pollution Control Bonds, City of Rockport, Series 2006A (a)	2025	3.90%	-	50,000	-
Unamortized Premium (Discount)				(695)	(733)
Total Pollution Control Bonds – I&M				311,305	311,267
Senior Unsecured Notes, Series C	2006	-	6.125%	-	300,000
Senior Unsecured Notes, Series A	2008	6.45%	6.45%	50,000	50,000
Senior Unsecured Notes, Series E	2012	6.375%	6.375%	100,000	100,000
Senior Unsecured Notes, Series F	2014	5.05%	5.05%	175,000	175,000
Senior Unsecured Notes, Series G	2015	5.65%	5.65%	125,000	125,000
Senior Unsecured Notes, Series D	2032	6.00%	6.00%	150,000	150,000
Senior Unsecured Notes, Series H	2037	6.05%	-	400,000	-
MTM of Fair Value Hedge				-	(530)
Unamortized Premium (Discount)				(3,254)	(1,602)
Total Senior Unsecured Notes – I&M				996,746	897,868
Spent Nuclear Fuel Liability (e)				247,084	235,805
Total Spent Nuclear Fuel Liability – I&M				247,084	235,805
Total I&M Long-term Debt				1,555,135	1,444,940
Less: Long-term Debt Due Within One Year				50,000	364,469
Long-term Debt				$ 1,505,135	$ 1,080,471

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
KPCo				(in thousands)	
Senior Unsecured Notes, Series B	2007	4.3148%	4.3148%	80,400	80,400
Senior Unsecured Notes, Series C	2007	4.368%	4.368%	69,564	69,564
Senior Unsecured Notes, Series A	2007	5.50%	5.50%	125,000	125,000
Senior Unsecured Medium Term Notes, Series A	2007	6.91%	6.91%	48,000	48,000
Senior Unsecured Medium Term Notes, Series A	2008	6.45%	6.45%	30,000	30,000
Senior Unsecured Notes, Series D	2032	5.625%	5.625%	75,000	75,000
MTM of Fair Value Hedge				(916)	(800)
Unamortized Premium (Discount)				(80)	(174)
Total Senior Unsecured Notes - KPCo				426,968	426,990
Notes Payable – Affiliated	2006	-	6.501%	-	40,000
Notes Payable – Affiliated	2015	5.25%	5.25%	20,000	20,000
Total Notes Payable – Affiliated – KPCo				20,000	60,000
Total KPCo Long-term Debt				446,968	486,990
Less: Long-term Debt Due Within One Year				322,048	39,771
Long-term Debt				$ 124,920	$ 447,219

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
OPCo				**(in thousands)**	
Pollution Control Bonds, Marshall Co., WV, Series C (a)	2014	3.60%	3.35%	$ 50,000	$ 50,000
Pollution Control Bonds, Mason Co., WV, Series C (a)	2016	3.60%	3.36%	50,000	50,000
Pollution Control Bonds, Marshall Co., WV, Series F (a)	2022	3.60%	3.35%	35,000	35,000
Pollution Control Bonds, Marshall Co., WV, Series E (a)	2022	3.75%	3.45%	50,000	50,000
Pollution Control Bonds, JMG Air Quality Revenue Bonds, 1997 Series A (a)	2022	5.5625%	5.5625%	19,565	19,565
Pollution Control Bonds, JMG Air Quality Revenue Bonds, 1997 Series B (a)	2023	5.5625%	5.5625%	19,565	19,565
Pollution Control Bonds, Ohio Air Quality Revenue Bonds, 1999 Series C (a)	2026	5.15%	5.15%	50,000	50,000
Pollution Control Bonds, JMG Air Quality Revenue Bonds, 2005 Series B (a)	2028	3.70%	3.10%	54,500	54,500
Pollution Control Bonds, JMG Air Quality Revenue Bonds, 2005 Series C (a)	2028	3.80%	3.15%	54,500	54,500
Pollution Control Bonds, JMG Air Quality Revenue Bonds, 2005 Series D (a)	2028	3.70%	3.16%	54,500	54,500
Pollution Control Bonds, JMG Air Quality Revenue Bonds, Series 2005 A (a)	2029	3.70%	3.15%	54,500	54,500
Pollution Control Bonds, West Virginia Econ. Dev. Auth., Series 2006A (a)	2036	3.85%	-	65,000	-
Total Pollution Control Bonds – OPCo				557,130	492,130
Senior Unsecured Medium Notes, Series A	2008	6.24%	6.24%	37,225	37,225
Senior Unsecured Notes, Series J	2010	5.30%	5.30%	200,000	200,000
Senior Unsecured Notes, Series D	2013	5.50%	5.50%	250,000	250,000
Senior Unsecured Notes, Series H	2014	4.85%	4.85%	225,000	225,000
Senior Unsecured Notes, Series K	2016	6.00%	-	350,000	-
Senior Unsecured Notes, Series I	2033	6.375%	6.375%	225,000	225,000
Senior Unsecured Notes, Series E	2033	6.60%	6.60%	250,000	250,000
Unamortized Premium (Discount)				(5,932)	(5,356)
Total Senior Unsecured Notes – OPCo				1,531,293	1,181,869
Notes Payable – Affiliated	2006	-	3.32%	-	200,000
Notes Payable – Affiliated	2015	5.25%	5.25%	200,000	200,000
Total Notes Payable – Affiliated – OPCo				200,000	400,000
Notes Payable – Nonaffiliated, JMG Funding Corp., Series B	2008	6.81%	6.81%	7,318	13,171
Notes Payable – Nonaffiliated, JMG Funding Corp., Series D	2009	6.27%	6.27%	25,000	31,500
Notes Payable – Nonaffiliated, JMG Funding Corp., Series F	2009	7.21%	7.21%	11,000	11,000
Notes Payable – Nonaffiliated, JMG Funding Corp., Series E	2009	7.49%	7.49%	70,000	70,000
Total Notes Payable – Nonaffiliated - OPCo				113,318	125,671
Total OPCo Long-term Debt				2,401,741	2,199,670
Less: Long-term Debt Due Within One Year				17,854	212,354
Long-term Debt				$ 2,383,887	$ 1,987,316

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
PSO				(in thousands)	
Pollution Control Bonds, Oklahoma Development Finance Auth., Series 2004 (a)	2014	3.60%	3.15%	$ 33,700	$ 33,700
Pollution Control Bonds, Red River Auth. of Texas Series 1996 (a)	2020	6.00%	6.00%	12,660	12,660
Total Pollution Control Bonds – PSO				46,360	46,360
Senior Unsecured Notes, Series D	2009	4.70%	4.70%	50,000	50,000
Senior Unsecured Notes, Series C	2010	4.85%	4.85%	150,000	150,000
Senior Unsecured Notes, Series E	2011	4.70%	4.70%	75,000	75,000
Senior Unsecured Notes, Series F	2016	6.15%	-	150,000	-
Senior Unsecured Notes, Series B	2032	6.00%	6.00%	200,000	200,000
Unamortized Premium (Discount)				(1,362)	(289)
Total Senior Unsecured Notes – PSO				623,638	474,711
Notes Payable – Affiliated	2006	-	3.35%	-	50,000
Total Notes Payable – Affiliated - PSO				-	50,000
Total PSO Long-term Debt				669,998	571,071
Less: Long-term Debt Due Within One Year				-	50,000
Long-term Debt				$ 669,998	$ 521,071
SWEPCo					
Pollution Control Bonds, Titus Co., Series 2004 (a)	2011	3.60%	3.10%	$ 41,135	$ 41,135
Pollution Control Bonds, Series 1996 Sabine River (a)	2018	-	6.10%	-	81,700
Pollution Control Bonds, Sabine River Auth. of Texas, Series 2006 (a)	2018	3.88%	-	81,700	
Pollution Control Bonds, Parish of DeSoto, Series 2004 (a)	2019	3.65%	3.40%	53,500	53,500
Unamortized Premium (Discount)				1,360	1,342
Total Pollution Control Bonds – SWEPCo				177,695	177,677
Senior Unsecured Notes, Series D	2015	4.90%	4.90%	150,000	150,000
Senior Unsecured Notes, Series C	2015	5.38%	5.375%	100,000	100,000
Unamortized Premium (Discount)				(178)	(199)
Total Senior Unsecured Notes – SWEPCo				249,822	249,801
First Mortgage Bonds, Series 1976A Siloam Springs (d)	2006	-	6.20%	-	5,070
First Mortgage Bonds, Series 1976B Siloam Springs (d)	2006	-	6.20%	-	1,000
First Mortgage Bonds, Series X (d)	2007	7.00%	7.00%	90,000	90,000
Unamortized Premium (Discount)				(48)	(119)
Total First Mortgage Bonds – SWEPCo				89,952	95,951
Notes Payable – Affiliated	2010	4.45%	4.45%	50,000	50,000
Total Notes Payable – Affiliated – SWEPCo				50,000	50,000
Notes Payable – Nonaffiliated, Sabine Mines	2007	6.36%	6.36%	4,000	4,000
Notes Payable – Nonaffiliated, Sabine Mines	2008	5.93675%	5.12688%	4,500	7,500
Notes Payable – Nonaffiliated, Dolet Hills Lignite Co., LLC	2011	4.47%	4.47%	19,998	26,683
Notes Payable – Nonaffiliated, Sabine Mines	2012	7.03%	7.03%	20,000	20,000
Total Notes Payable – Nonaffiliated – SWEPCo				48,498	58,183
Notes Payable to Trust, 5.25% TPS Flexible	2043	5.25%	5.25%	113,403	113,403
Unamortized Premium (Discount)				(364)	(374)
Total Notes Payable to Trust - SWEPCo				113,039	113,029
Total SWEPCo Long-term Debt				729,006	744,641
Less: Long-term Debt Due Within One Year				102,312	15,755
Long-term Debt				$ 626,694	$ 728,886

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
TCC				(in thousands)	
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2001A (a)	2006	-	4.55%	$ -	$ 100,635
Pollution Control Bonds, Guadalupe-Blanco River Auth., Series 2005 (a)	2015	3.75%	3.35%	40,890	40,890
Pollution Control Bonds, Red River Auth. of Texas, Series 1996(a)	2020	6.00%	6.00%	6,330	6,330
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005C-1 (a)	2028	3.65%	3.30%	60,000	60,000
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005C-2 (a)	2028	3.60%	3.45%	60,265	60,265
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005B (a)	2030	-	3.15%	-	50,000
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005B (a)	2030	4.55%	-	50,000	-
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005A (a)	2030	-	3.30%	-	111,700
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005A (a)	2030	4.40%	-	111,700	-
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 1996 (a)	2030	6.125%	6.125%	60,000	60,000
Unamortized Premium (Discount)				(208)	(217)
Total Pollution Control Bonds – TCC				388,977	489,603
Senior Unsecured Notes, Series A	2013	-	5.50%	-	275,000
Senior Unsecured Notes, Series B	2033	6.65%	6.65%	275,000	275,000
Unamortized Premium (Discount)				(1,170)	(1,958)
Total Senior Unsecured Notes – TCC				273,830	548,042
First Mortgage Bonds, Series GG (d)	2008	7.125%	7.125%	18,581	18,581
Total First Mortgage Bonds – TCC				18,581	18,581
Notes Payable – Affiliated	2007	-	4.58%	-	150,000
Total Notes Payable – Affiliated – TCC				-	150,000
Securitization Bonds, Class 2002 A-2	2008 (f)	5.01%	5.01%	81,649	133,914
Securitization Bonds, Class 2006 A-1 (g)	2010 (f)	4.98%	-	217,000	-
Securitization Bonds, Class 2002 A-3	2010 (f)	5.56%	5.56%	107,094	107,094
Securitization Bonds, Class 2006 A-2 (g)	2013 (f)	4.98%	-	341,000	-
Securitization Bonds, Class 2002 A-4	2013 (f)	5.96%	5.96%	214,927	214,927
Securitization Bonds, Class 2006 A-3 (g)	2015 (f)	5.09%	-	250,000	-
Securitization Bonds, Class 2002 A-5	2016 (f)	6.25%	6.25%	191,857	191,857
Securitization Bonds, Class 2006 A-4 (g)	2018 (f)	5.17%	-	437,000	-
Securitization Bonds, Class 2006 A-5 (g)	2020 (f)	5.3063%	-	494,700	-
Unamortized Premium (Discount)				(1,001)	(522)
Total Securitization Bonds - TCC				2,334,226	647,270
Total TCC Long-term Debt				3,015,614	1,853,496
Less: Long-term Debt Due Within One Year				78,227	152,900
Long-term Debt				$ 2,937,387	$ 1,700,596

Type of Debt	Maturity	Interest Rates at December 31, 2006	Interest Rates at December 31, 2005	December 31, 2006	December 31, 2005
TNC				**(in thousands)**	
Pollution Control Bonds, Red River Auth. of Texas, Series 1996 (a)	2020	6.00%	6.00%	$ 44,310	$ 44,310
Total Pollution Control Bonds – TNC				44,310	44,310
Senior Unsecured Notes, Series A	2013	5.50%	5.50%	225,000	225,000
Unamortized Premium (Discount)				(525)	(615)
Total Senior Unsecured Notes - TNC				224,475	224,385
First Mortgage Bonds, Series P (d)	2007	7.75%	7.75%	8,151	8,151
Unamortized Premium (Discount)				-	(1)
Total First Mortgage Bonds – TNC				8,151	8,150
Total TNC Long-term Debt				276,936	276,845
Less: Long-term Debt Due Within One Year				8,151	-
Long-term Debt				$ 268,785	$ 276,845

(a) Under the terms of the pollution control bonds, each Registrant Subsidiary is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Interest payments range from monthly to semi-annually.

(b) The fixed rate bonds of AEGCo due in 2025 are subject to mandatory tender for purchase on July 15, 2011. Consequently, the fixed rate bonds have been classified for repayment purposes in 2011.

(c) I&M's pollution control bonds for City of Rockport, Series 2002A maturing in 2025 provides for bonds to be tendered in 2007. Therefore, these pollution control bonds have been classified for payment in 2007.

(d) First mortgage bonds are secured by the first mortgage liens on Electric Property, Plant and Equipment. Certain supplemental indentures to the first mortgage liens contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually. TCC's first mortgage bonds were defeased in 2004 and TNC's first mortgage bonds were defeased in 2005.

(e) 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 $274 million and $264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts on its Consolidated Balance Sheets at December 31, 2006 and 2005, respectively.

(f) This date represents the scheduled final payment date for this class of TCC's securitization bonds. The contractual maturity date is one to two years later. These bonds have been classified for repayment purposes based on the scheduled final payment date.

(g) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued $1.7 billion in securitization bonds. TFII is the sole owner of the transition charges and the original transition property. The holders of the securitization bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.

At December 31, 2006 future annual long-term debt payments are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2007	$ -	$ 324,191	$ -	$ 50,000	$ 322,048
2008	-	199,665	112,000	50,000	30,000
2009	-	150,017	-	45,000	-
2010	-	250,019	250,000	-	-
2011	45,000	250,022	-	-	-
Later Years	-	1,439,683	842,245	1,414,083	95,000
Total Principal Amount	45,000	2,613,597	1,204,245	1,559,083	447,048
Unamortized Discount	(163)	(14,933)	(6,923)	(3,948)	(80)
Total	$ 44,837	$ 2,598,664	$ 1,197,322	$ 1,555,135	$ 446,968

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2007	$ 17,854	$ -	$ 102,312	$ 78,227	$ 8,151
2008	55,188	-	5,906	143,419	-
2009	77,500	50,000	4,406	137,141	-
2010	200,000	150,000	54,406	147,833	-
2011	-	75,000	42,603	159,443	-
Later Years	2,057,131	396,360	518,603	2,351,930	269,310
Total Principal Amount	2,407,673	671,360	728,236	3,017,993	277,461
Unamortized Premium/(Discount)	(5,932)	(1,362)	770	(2,379)	(525)
Total	$ 2,401,741	$ 669,998	$ 729,006	$ 3,015,614	$ 276,936

In January 2007, SWEPCo issued a 5.55%, $250 million Senior Unsecured Note due in January 2017.

In January 2007, SWEPCo retired $548 thousand of 4.47% notes.

In January 2007, TCC retired $32.1 million of 5.01% securitization bonds.

Dividend Restrictions

Under the Federal Power Act, the Registrants Subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2006 and 2005, is reported as Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2006 and 2005, are reported as Notes Payable to Trust within Long-term Debt – Nonaffiliated.

The business trust is treated as a nonconsolidated subsidiary of its parent company. The only asset of the business trust is the subordinated debentures issued by its parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit and Short-term Debt – 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 amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2006 and 2005 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized limits for the years ended December 31, 2006 and 2005 are described in the following tables:

Year Ended December 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 December 31, 2006	Authorized Short-Term Borrowing Limit
	(in thousands)					
AEGCo	$ 79,828	$ 2,247	$ 21,940	$ 2,247	$ (53,646)	$ 125,000
APCo	283,872	314,064	169,937	149,103	(34,975)	600,000
CSPCo	48,337	95,977	14,703	45,886	(696)	350,000
I&M	128,071	322,067	62,659	292,504	(91,173)	500,000
KPCo	46,156	11,993	25,994	4,384	(30,636)	200,000
OPCo	351,302	40,382	102,302	15,845	(181,281)	600,000
PSO	167,456	146,657	94,328	58,541	(76,323)	300,000
SWEPCo	189,021	24,209	66,848	9,411	(188,965)	350,000
TCC	117,429	818,415	44,416	199,100	394,004	600,000
TNC	23,660	34,574	7,988	8,381	(235)	250,000

Year Ended December 31, 2005:

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 December 31, 2005	Authorized Short-Term Borrowing Limit
	(in thousands)					
AEGCo	$ 45,694	$ 9,305	$ 15,551	$ 4,272	$ (35,131)	$ 125,000
APCo	242,718	321,977	134,079	44,622	(194,133)	600,000
CSPCo	180,397	181,238	143,885	94,083	(17,609)	350,000
I&M	203,248	11,768	87,208	5,797	(93,702)	500,000
KPCo	9,964	35,779	2,969	12,653	(6,040)	200,000
OPCo	162,907	182,495	64,142	75,186	(70,071)	600,000
PSO	101,962	66,159	30,205	32,632	(75,883)	300,000
SWEPCo	55,756	188,215	17,657	34,490	(28,210)	350,000
TCC	320,508	120,937	109,463	39,060	(82,080)	600,000
TNC	13,606	119,569	10,930	58,067	34,286	250,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31, 2006	2005	2004
Maximum Interest Rate	5.41%	4.49%	2.24%
Minimum Interest Rate	3.32%	1.63%	0.89%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2006, 2005 and 2004 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Year Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
Company			(in percentage)			
AEGCo	4.79	3.27	1.47	5.11	3.17	1.91
APCo	4.63	3.40	1.68	4.93	3.15	1.48
CSPCo	4.76	3.95	1.50	4.37	3.03	1.69
I&M	4.80	3.43	1.45	3.84	2.12	1.93
KPCo	4.74	3.70	1.59	4.97	2.70	1.61
OPCo	4.74	3.86	1.29	5.12	2.57	1.46
PSO	5.02	3.37	1.38	4.35	3.56	1.80
SWEPCo	4.79	4.10	1.37	4.45	2.62	1.67
TCC	4.79	3.18	1.40	4.24	2.43	1.47
TNC	4.60	4.41	1.09	4.56	3.29	1.56

Interest expense related to the Utility Money Pool is included in Interest Expense in each of the Registrant Subsidiaries' Financial Statements. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

	Year Ended December 31,		
	2006	2005	2004
Company		(in thousands)	
AEGCo	$ 1,046	$ 418	$ 338
APCo	2,656	2,830	1,136
CSPCo	284	280	32
I&M	2,772	2,854	1,127
KPCo	1,065	18	65
OPCo	4,473	1,056	51
PSO	3,037	637	486
SWEPCo	3,234	293	219
TCC	724	3,272	177
TNC	274	8	8

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' Financial Statements. Interest income earned from amounts advanced to the Utility Money Pool by Registrant Subsidiary were:

	Year Ended December 31,		
	2006	2005	2004
Company		(in thousands)	
AEGCo	$ -	$ 24	$ 1
APCo	5,007	543	24
CSPCo	1,231	2,757	1,076
I&M	967	6	84
KPCo	30	287	177
OPCo	63	1,129	1,965
PSO	941	431	76
SWEPCo	216	649	649
TCC	5,591	66	1,445
TNC	112	1,897	587

In the third quarter of 2006, TNC created a new wholly-owned subsidiary, AEP Texas North Generation Company, LLC (TNGC). Following the creation of this subsidiary, TNC transferred all of its mothballed generation assets and related liabilities to this new subsidiary, effectively completing the business separation requirement of the Texas Restructuring Legislation. Subsequently, TNGC became a participant in the Nonutility Money Pool. As of December 31, 2006, TNGC had $13.8 million in loans to the Nonutility Money Pool. For the year ended December 31, 2006, TNGC paid an immaterial amount of interest expense for borrowings from the Nonutility Money Pool and earned $233 thousand in interest income for loans to the Nonutility Money Pool. For the year ended December 31, 2006, the average interest rate for funds either borrowed from or loaned to the Nonutility Money Pool by TNGC was 5.36%.

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		At December 31, 2006		At December 31, 2005	
		Outstanding Amount	Interest Rate	Outstanding Amount	Interest Rate
Company	Type of Debt	(in millions)		(in millions)	
OPCo	Commercial Paper – JMG (a)	$ 1	5.56 %	$ 10	4.47 %
SWEPCo	Line of Credit – Sabine	17	6.38 %	1	5.31 %

(a) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires on August 24, 2007. AEP intends to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2006	2005	2004
	($ in millions)		
Proceeds from Sale of Accounts Receivable	$ 6,849	$ 5,925	$ 5,163
Loss on Sale of Accounts Receivable	$ 31	$ 18	$ 7
Average Variable Discount Rate	5.02%	3.23%	1.50%

	December 31, 2006	2005
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 87	106
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	85	103
Retained Interest if 20% Adverse Change in Uncollectible Accounts	83	101

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2006	2005
	(in millions)	
Customer Accounts Receivable Retained	$ 676	$ 826
Accrued Unbilled Revenues Retained	350	374
Miscellaneous Accounts Receivable Retained	44	51
Allowance for Uncollectible Accounts Retained	(30)	(31)
Total Net Balance Sheet Accounts Receivable	1,040	1,220
Customer Accounts Receivable Securitized	536	516
Total Accounts Receivable Managed	$ 1,576	$ 1,736
Net Uncollectible Accounts Written Off	$ 31	$ 74

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $29 million and $30 million at December 31, 2006 and 2005, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring arrangement, participating Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the participant's Statements of Income.

The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

Company	As of December 31, 2006	2005
	(in millions)	
APCo	$ 102.1	$ 77.1
CSPCo	142.5	124.4
I&M	94.5	102.7
KPCo	44.0	38.7
OPCo	140.2	122.1
PSO	119.4	146.5
SWEPCo	102.7	100.4

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

Company	Year Ended December 31, 2006	2005	2004
		(in millions)	
APCo	$ 6.3	$ 5.1	$ 3.9
CSPCo	13.7	7.4	10.2
I&M	9.2	7.4	6.5
KPCo	3.4	2.9	2.6
OPCo	11.1	6.1	7.7
PSO	16.3	11.1	8.9
SWEPCo	10.5	8.3	5.8

16. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit" sections of Note 15.

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the AEP West companies to maintain adequate annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy each AEP West company contributes that is sold to third parties.

In February 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement. Pursuant to Texas electric restructuring law, those companies exited the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the System Integration Agreement. The filings were approved effective May 1, 2006 and April 1, 2006, respectively.

System Integration Agreement

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies and West companies zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

In November 2005, AEP filed with the FERC a proposed amendment to the System Integration Agreement to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such Registrant Subsidiary at rates approved (other than in Ohio, Virginia and the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation (see Note 4). In the ERCOT area of Texas, such rates are market-based.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2006, 2005 and 2004:

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2006						
Sales to East System Pool	$ 163,633	$ 76,938	$ 285,048	$ 57,921	$ 610,865	$ -
Direct Sales to East Affiliates	70,402	-	-	-	65,386	309,604
Direct Sales to West Affiliates	20,009	12,117	12,538	4,801	15,306	-
Natural Gas Contracts with AEPES	(19,998)	(9,705)	(9,296)	(4,698)	(17,219)	-
Other	4,546	6,376	2,743	263	11,005	-
Total Revenues	$ 238,592	$ 85,726	$ 291,033	$ 58,287	$ 685,343	$ 309,604

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
	(in thousands)					
2005						
Sales to East System Pool	$ 162,014	$ 70,165	$ 314,677	$ 49,791	$ 542,364	$ -
Direct Sales to East Affiliates	70,130	-	-	-	64,449	270,545
Direct Sales to West Affiliates	25,776	14,162	14,998	6,122	19,562	-
Natural Gas Contracts with AEPES	60,793	34,324	33,461	14,586	46,751	-
Other	3,620	5,759	2,896	304	8,726	-
Total Revenues	$ 322,333	$ 124,410	$ 366,032	$ 70,803	$ 681,852	$ 270,545

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
	(in thousands)					
2004						
Sales to East System Pool	$ 138,566	$ 69,309	$ 250,356	$ 36,853	$ 487,794	$ -
Direct Sales to East Affiliates	62,018	-	-	-	55,017	241,578
Direct Sales to West Affiliates	22,238	13,322	14,682	5,206	17,899	-
Natural Gas Contracts with AEPES	25,733	15,732	17,886	6,306	22,971	-
Other	3,573	6,384	3,386	352	10,676	-
Total Revenues	$ 252,128	$ 104,747	$ 286,310	$ 48,717	$ 594,357	$ 241,578

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2006				
Direct Sales to East Affiliates	$ 227	$ 220	$ -	$ -
Direct Sales to West Affiliates	47,184	37,284	-	17
Other	4,582	4,941	6,403	33,208
Total Revenues	$ 51,993	$ 42,445	$ 6,403	$ 33,225

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2005				
Direct Sales to West Affiliates	$ 33,992	$ 61,555	$ -	$ 98
Other	5,686	3,853	14,973	47,066
Total Revenues	$ 39,678	$ 65,408	$ 14,973	$ 47,164

Related Party Revenues	PSO	SWEPCo	TCC	TNC
	(in thousands)			
2004				
Sales to West System Pool	$ 103	$ 521	$ -	$ 159
Direct Sales to East Affiliates	2,652	1,878	188	78
Direct Sales to West Affiliates	3,203	63,141	3,027	71
Other	4,732	5,650	43,824	51,372
Total Revenues	$ 10,690	$ 71,190	$ 47,039	$ 51,680

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2006, 2005, and 2004:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2006					
Purchases from East System Pool	$ 492,619	$ 365,425	$ 126,345	$ 99,166	$ 108,151
Direct Purchases from East Affiliates	-	-	216,723	92,881	-
Direct Purchases from West Affiliates	137	85	88	33	104
Gas Purchases from AEPES	-	-	-	-	5,396
Total Purchases	$ 492,756	$ 365,510	$ 343,156	$ 192,080	$ 113,651

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2005					
Purchases from East System Pool	$ 453,600	$ 362,959	$ 116,735	$ 95,187	$ 104,777
Direct Purchases from East Affiliates	-	-	189,382	81,163	12,113
Total Purchases	$ 453,600	$ 362,959	$ 306,117	$ 176,350	$ 116,890

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2004					
Purchases from East System Pool	$ 370,038	$ 346,463	$ 102,760	$ 68,072	$ 84,042
Direct Purchases from East Affiliates	-	-	169,103	72,475	4,334
Direct Purchases from West Affiliates	915	539	589	211	979
Total Purchases	$ 370,953	$ 347,002	$ 272,452	$ 140,758	$ 89,355

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2006				
Purchases from West System Pool	$ -	$ -	$ -	$ 4
Direct Purchases from East Affiliates	37,504	27,257	-	11
Direct Purchases from West Affiliates	31,902	47,201	-	5,933
Total Purchases	$ 69,406	$ 74,458	$ -	$ 5,948

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2005				
Purchases from East System Pool	$ 43,516	$ 36,573	$ -	$ -
Direct Purchases from East Affiliates	281	278	-	-
Direct Purchases from West Affiliates	61,564	34,060	-	23
Total Purchases	$ 105,361	$ 70,911	$ -	$ 23

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2004				
Purchases from East System Pool	$ 66	$ 177	$ -	$ -
Purchases from West System Pool	49	191	-	568
Direct Purchases from East Affiliates	45,689	24,988	1,984	1,278
Direct Purchases from West Affiliates	58,197	3,698	4,156	3,365
Total Purchases	$ 104,001	$ 29,054	$ 6,140	$ 5,211

The above summarized related party revenues and expenses are reported as consolidated and are presented as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the income statements of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's East companies and AEP West companies zones. Similar to the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Equalization Agreement (TEA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net charges (credits) allocated among the parties to the TEA during the years ended December 31, 2006, 2005 and 2004:

Company	2006	2005	2004
		(in thousands)	
APCo	$ (16,000)	$ 8,900	$ (500)
CSPCo	46,200	34,600	37,700
I&M	(37,300)	(47,000)	(40,800)
KPCo	(2,000)	(3,500)	(6,100)
OPCo	9,100	7,000	9,700

The net charges (credits) shown above are recorded in Other Operation on the Registrant Subsidiaries' income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. Prior to September 2005, TCA also provided for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT. Since then, these allocations have been governed by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net charges (credits) allocated among parties to the TCA prior to September 2005, and pursuant to the SPP OATT and ERCOT protocols as described above during the years ended December 31, 2006, 2005 and 2004:

Company	2006	2005	2004
		(in thousands)	
PSO	$ 1,800	$ 3,500	$ 8,100
SWEPCo	(1,900)	5,200	13,800
TCC	1,100	(3,800)	(12,200)
TNC	(1,000)	(4,900)	(9,700)

The net charges (credits) shown above are recorded in the Other Operation on the Registrant Subsidiaries' income statements.

CSPCo coal purchases from AEP Coal, Inc.

During 2004, CSPCo purchased approximately 330,000 tons of coal from AEP Coal. The coal was delivered (at CSPCo's expense) to the Conesville Plant for a price of $26.15 per ton. During 2004, CSPCo's purchases from AEP Coal totaled $9.5 million. These purchases were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

AEP Coal and CSPCo were parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, in 2004 AEP Coal transferred coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivered the coal via trucks to either CSPCo's Conesville Preparation Plant or one of CSPCo's power plants for a rate of $1.25 per ton. During 2004, CSPCo paid AEP Coal $1 million. These transloading costs were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

As a result of management's decision to exit our non-core businesses, AEP Coal, Inc. (AEP Coal) was sold in April 2004.

Coal Transactions with AEP Coal Marketing

AEP Coal Marketing, a wholly-owned subsidiary of AEP, enters into sale and purchase transactions with certain operating companies. The transactions are executed on a spot basis and are performed at cost for the operating companies' fuel requirements. During 2005 and 2004, the only transactions were immaterial purchases by I&M and OPCo from AEP Coal Marketing. There were no transactions in 2006.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. In the future, PSO and SWEPCo may also be allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents Registrant Subsidiaries' risk management liabilities related to DETM at December 31:

Company	2006	2005
	(in thousands)	
APCo	$ (11,224)	$ (12,318)
CSPCo	(7,154)	(7,142)
I&M	(7,517)	(7,294)
KPCo	(2,692)	(2,932)
OPCo	(8,503)	(9,810)

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who purchased 100% of the available generating capacity from the plant through May 2006. The agreement was renewed and extends through May 2007. The related purchases of gas managed by AEPES were as follows:

	Year Ended December 31,		
Company	2006	2005	2004
		(in thousands)	
APCo	$ 1,660	$ 3,905	$ 1,230
CSPCo	1,016	2,113	732
I&M	1,065	2,255	805
KPCo	398	924	286
OPCo	1,257	2,916	1,281

These purchases are reflected in Purchased Electricity for Resale on the Registrant Subsidiaries' income statements.

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) for such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement ends in December 2022. See Affiliated Revenues and Purchases section of this note.

Jointly-Owned Electric Utility Plants

APCo and OPCo jointly own two power plants. The costs of operating these facilities are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective Consolidated Statements of Income. Each company's investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

AEGCo and I&M jointly own one generating unit and jointly lease the other generating unit of the Rockport Plant. The costs of operating this facility are equally apportioned between AEGCo and I&M since each company has a 50% interest. Each company's share of costs is included in the appropriate expense accounts on its respective income statements. Each company's investment in these plants is included in Property, Plant and Equipment on its respective balance sheets.

PSO, TCC and TNC jointly own the Oklaunion power plant along with two nonaffiliated companies. The costs of operating the facility are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective income statement. PSO's and TNC's investment in this plant is included in Property, Plant and Equipment on its respective balance sheets, while TCC's share is included in Assets Held For Sale – Texas Generation Plant. TCC sold its share to one of the nonaffiliated owners in February 2007.

Cook Coal Terminal

In 2006, 2005 and 2004, Cook Coal Terminal, a division of OPCo, performed coal transloading services at cost for APCo and I&M. OPCo included revenues for these services in Other-Affiliated and expenses in Other Operation on its Consolidated Statements of Income. The coal transloading revenues were as follows:

	Year Ended December 31,		
	2006	2005	2004
Company	(in thousands)		
APCo	$ 899	$ 1,770	$ 730
I&M	15,869	13,653	14,275

APCo and I&M recorded the cost of the transloading services in Fuel on their respective Consolidated Balance Sheets.

In addition, Cook Coal Terminal provided coal transloading services for OVEC in 2006 and 2005. OPCo recorded revenue as Other – Nonaffiliated on its Consolidated Statements of Income in the amounts of $172 thousand and $513 thousand in 2006 and 2005, respectively. OVEC is 43.47% owned by AEP and CSPCo.

In 2006, 2005 and 2004, Cook Coal Terminal also performed railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo includes revenues for these services in Sales to AEP Affiliates and expenses in Other Operation on its Consolidated Statements of Income. The railcar maintenance revenues were as follows:

	Year Ended December 31,		
	2006	2005	2004
Company		(in thousands)	
APCo	$ 278	$ -	$ -
I&M	2,491	2,816	2,634
PSO	905	117	-
SWEPCo	433	163	-

APCo, I&M, PSO and SWEPCo record the cost of the railcar maintenance services in Fuel on their respective balance sheets.

SWEPCo Railcar Facility

SWEPCo operates a railcar maintenance facility in Alliance, Nebraska. The facility performs maintenance on its own railcars as well as railcars belonging to I&M, PSO and third parties. SWEPCo billed I&M $1,224 thousand and $453 thousand for railcar services provided in 2006 and 2005, respectively, and billed PSO $905 thousand and $964 thousand in 2006 and 2005, respectively. These billings, for SWEPCo, and costs, for I&M and PSO, are recorded in Fuel on the Registrant Subsidiaries' respective balance sheets.

I&M Barging and Other Services

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as Other – Affiliated on its Consolidated Statements of Income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2006	2005	2004
Company		(in millions)	
I&M – revenues	$ 47.9	$ 43.1	$ 38.2
AEGCo – expense	14.9	11.4	9.5
APCo – expense	14.5	18.5	13.0
KPCo – expense	0.1	0.1	0.1
OPCo – expense	2.1	2.5	4.9
MEMCO – expense (Nonutility subsidiary of AEP)	16.3	10.6	10.7

Services Provided by MEMCO

AEP MEMCO LLC (MEMCO) provides services for barge towing and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation. For the years ended December 31, 2006, 2005 and 2004, I&M recorded $16.0 million, $14.1 million and $12.6 million, respectively.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the Registrant Subsidiary and is reimbursed. The Registrant Subsidiaries recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the Registrant Subsidiaries:

	Year Ended December 31,		
	2006	**2005**	**2004**
Company		**(in thousands)**	
CSPCo	$ 617	$ 790	$ 544
I&M	1,826	3,620	2,134
KPCo	181	285	182
OPCo	2,831	2,684	2,731
PSO	801	21	4
SWEPCo	2	-	90

In addition, APCo billed OVEC and IKEC a total of $951 thousand, $957 thousand and $1,343 thousand for 2006, 2005 and 2004, respectively.

Affiliate Railcar Agreement

The Registrant Subsidiaries have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. The Registrant Subsidiaries record these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on their balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on the Registrant Subsidiaries' respective 2006 balance sheets:

	Billing Company						
	AEP Transportation (a)	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**	**Total**
Billed Company				**(in thousands)**			
APCo	$ 1	$ -	$ 289	$ 1,786	$ 46	$ 65	$ 2,187
I&M	310	176	-	1,016	487	735	2,724
KPCo	-	384	-	233	-	-	617
OPCo	-	231	700	-	-	-	931
PSO	321	145	962	105	-	382	1,915
SWEPCo	883	20	2,194	845	456	-	4,398
Total	$ 1,515	$ 956	$ 4,145	$ 3,985	$ 989	$ 1,182	$ 12,772

(a) AEP Transportation is a 100%-owned nonutility subsidiary of AEP, Inc.

I&M Urea Transloading

I&M provides urea transloading services to APCo, KPCo, and OPCo. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M records revenues from urea transloading services as Other – Affiliated on its Consolidated Statements of Income. The affiliates record costs paid to I&M for barging services as Fuel and Other Consumables Used for Electric Generation on their respective statements of income. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2006	2005	2004
Company		(in thousands)	
I&M – revenues	$ 853	$ 1,412	$ 896
APCo – expense	413	644	428
KPCo – expense	68	133	86
OPCo – expense	372	635	382

In addition, I&M provided transloading services to OVEC. I&M recorded the revenue, which totaled $121 thousand, $215 thousand and $128 thousand for 2006, 2005 and 2004, respectively, in Other – Nonaffiliated on its Consolidated Statements of Income.

Gas Purchases from HPL

Prior to its sale in January 2005, HPL acquired physical gas in the spot market. The gas was then purchased by TCC and TNC at cost for their fuel requirements. These purchases are included in Fuel from Affiliates for Electricity Generation on TCC's and TNC's respective income statements. The purchases from HPL were as follows:

	Year Ended December 31,	
	2005	2004
Company	(in thousands)	
TCC	$ -	$ 129,682
TNC	42	45,767

OPCo Indemnification Agreement with AEP Resources

OPCo had an indemnification agreement with AEP Resources (AEPR), a nonutility subsidiary of AEP, whereby AEPR held OPCo harmless from market exposure related to OPCo's Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2006, 2005 and 2004, AEPR paid OPCo $14.9 million, $29.6 million and $21.5 million, respectively, which is reported in OPCo's Other Operation on its Consolidated Statements of Income. As a result of the sale of the Plaquemine Cogeneration Facility and subsequent termination of OPCo's Power Purchase and Sale Agreement in November 2006, no indemnification payments are expected in 2007.

Purchased Power from OVEC

The amounts of power purchased by the Registrant Subsidiaries from OVEC, which is 43.47% owned by AEP and CSPCo, for the years ended December 31, 2006, 2005 and 2004 were:

	Year Ended December 31,		
	2006	2005	2004
Company		(in thousands)	
APCo	$ 82,422	$ 77,337	$ 62,101
CSPCo	22,821	20,602	16,724
I&M	38,961	30,961	27,474
OPCo	78,579	66,680	55,052

The amounts shown above are recoverable from customers and are included in Purchased Electricity for Resale in the Registrant Subsidiaries' respective Consolidated Statements of Income.

AEP Power Pool Purchases from OVEC

Under a new agreement in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in the Registrant Subsidiaries' respective Consolidated Statements of Income. The agreement expired in December 2006. The following table shows the amounts recorded by the Registrant Subsidiaries in 2006:

Company	Year Ended December 31, 2006 (in thousands)
APCo	$ 11,284
CSPCo	6,915
I&M	7,189
KPCo	2,706
OPCo	8,576

Purchased Power from Sweeny

On behalf of the AEP West companies, CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, which is 50% owned by AEP. The PPA is for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. Prior to May 1, 2006, the purchase of Sweeny power and its sale to nonaffiliates were shared among the AEP West companies under the CSW Operating Agreement. After May 1, 2006, the purchases and sales are shared between PSO and SWEPCo. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4 and "CSW Operating Agreement" section of this note. The purchases from Sweeny were:

	Year Ended December 31,	
	2006	2005
Company	(in thousands)	
PSO	$ 53,354	$ 57,742
SWEPCo	62,794	50,618
TCC	703	4,560
TNC	4,229	27,804

The amounts shown above are recorded in Purchased Electricity for Resale on the Registrant Subsidiaries' respective income statements.

OPCo Coal Transfers

In 2006, OPCo sold 115,877 tons of coal from its Mitchell plant inventory to APCo for $4.8 million. The coal was sold at cost, based on a weighted average cost method of carrying inventory. APCo paid for the cost of transporting the coal from OPCo's facility to its delivery points at APCo's Amos plant and Sporn plant. The amount above was transferred from Fuel on OPCo's Consolidated Balance Sheet to APCo's Consolidated Balance Sheet at the time of the sale.

In 2005, OPCo sold 142,226 tons of coal from its Mitchell plant inventory to APCo for $6.0 million. The coal was sold at cost, based on a weighted average cost method of carrying inventory. APCo paid for the cost of transporting the coal from OPCo's facility to its delivery point at APCo's Amos plant. The amount above was transferred from Fuel on OPCo's Consolidated Balance Sheet to APCo's Consolidated Balance Sheet at the time of the sale.

In 2005, OPCo also sold 30,844 tons of coal from its Gavin plant inventory to OVEC for $1 million. The coal was sold at cost, based on a weighted average cost method of carrying inventory. OVEC paid for the cost of transporting the coal from OPCo's facility to its delivery point at OVEC's Kyger Creek plant. The coal inventory was removed from Fuel on OPCo's Consolidated Balance Sheet at the time of the sale.

Sales of Property

The Registrant Subsidiaries had sales of electric property individually amounting to $100,000 or more, for the years ended December 31, 2006, 2005 and 2004 as shown in the following table:

Companies	2006 (in thousands)
APCo to OPCo	$ 1,037
CSPCo to OPCo	592
I&M to CSPCo	173
I&M to SWEPCo	111
I&M to WPCo	201
KPCo to APCo	191
OPCo to APCo	3,822
OPCo to KPCo	1,324
OPCo to PSO	760

Companies	2005 (in thousands)
APCo to I&M	$ 554
APCo to OPCo	637
I&M to APCo	1,135
I&M to OPCo	3,423
KPCo to OPCo	101
OPCo to APCo	1,057
OPCo to I&M	2,142

Companies	2004 (in thousands)
APCo to OPCo	$ 2,992
I&M to APCo	1,630

In addition, the Registrant Subsidiaries had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2006, 2005 and 2004 as shown in the following table:

2006

Seller	Purchaser (in thousands) APCo	CSPCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	TCC	TNC	WPCo	TOTAL
APCo	$ -	$ 17	$ 187	$ 676	$ 3,206	$ 2,019	$ 157	$ 669	$ 1,631	$ -	$ 459	$ 9,021
CSPCo	87	-	2	2	1	661	17	-	-	-	-	770
I&M	86	44	-	-	18	2,052	25	158	2	-	10	2,395
KGPCo	179	-	-	-	-	1	-	-	179	-	-	359
KPCo	2,178	75	40	11	-	254	28	-	3	-	9	2,598
OPCo	1,750	2,545	910	-	504	-	330	211	1	-	391	6,642
PSO	1	1	26	-	-	1	-	129	30	2	-	190
SWEPCo	16	-	-	-	-	12	95	-	37	-	-	160
TCC	12	-	-	36	-	18	10	50	-	1,266	-	1,392
TNC	-	-	-	-	-	-	17	4	209	-	-	230
WPCo	7	28	21	-	3	247	8	-	-	-	-	314
Total	$ 4,316	$ 2,710	$ 1,186	$ 725	$ 3,732	$ 5,265	$ 687	$ 1,221	$ 2,092	$ 1,268	$ 869	$ 24,071

2005

	Purchaser											
Seller	**APCo**	**CSPCo**	**I&M**	**KGPCo**	**KPCo**	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**	**WPCo**	**TOTAL**
						(in thousands)						
APCo	$ -	$ 9	$ 1,847	$ 371	$ 1,577	$ 677	$ 208	$ 210	$ 357	$ -	$ 717	$ 5,973
CSPCo	36	-	23	-	8	605	47	29	-	-	-	748
I&M	59	8	-	4	22	2,903	-	3	-	-	19	3,018
KGPCo	270	-	4	-	-	19	-	-	-	-	-	293
KPCo	381	1	-	1	-	135	-	-	-	-	-	518
OPCo	1,246	1,901	2,504	28	304	-	182	94	69	-	335	6,663
PSO	12	-	-	-	-	-	-	52	8	3	-	75
SWEPCo	10	-	-	-	-	4	67	-	40	3	-	124
TCC	164	-	2	-	-	29	2	130	-	1,642	-	1,969
TNC	-	-	-	-	-	-	-	17	317	-	-	334
WPCo	-	-	-	-	-	196	-	-	-	-	-	196
Total	$ 2,178	$ 1,919	$ 4,380	$ 404	$ 1,911	$ 4,568	$ 506	$ 535	$ 791	$ 1,648	$ 1,071	$ 19,911

2004

	Purchaser											
Seller	**APCo**	**CSPCo**	**I&M**	**KGPCo**	**KPCo**	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**	**WPCo**	**TOTAL**
						(in thousands)						
APCo	$ -	$ 12	$ 138	$ 314	$ 687	$ 284	$ 3	$ -	$ 48	$ -	$ 5	$ 1,491
CSPCo	31	-	19	-	4	554	-	14	-	-	-	622
I&M	21	12	-	-	16	1,208	-	-	-	-	8	1,265
KGPCo	102	-	-	-	-	5	-	-	-	-	-	107
KPCo	200	1	2	7	-	120	-	-	-	-	10	340
OPCo	627	1,229	1,176	1	206	-	-	34	18	-	190	3,481
PSO	40	-	-	-	-	6	-	74	10	1	-	131
SWEPCo	1	31	40	-	5	1	49	-	124	12	-	263
TCC	6	-	20	-	-	67	1	26	-	810	-	930
TNC	20	-	-	-	-	8	9	7	227	-	-	271
WPCo	-	-	8	-	-	122	-	-	-	-	-	130
Total	$ 1,048	$ 1,285	$ 1,403	$ 322	$ 918	$ 2,375	$ 62	$ 155	$ 427	$ 823	$ 213	$ 9,031

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, portions of which were loaned to the Registrant Subsidiaries. The debt is reflected in Long-term Debt – Affiliated on the Registrant Subsidiaries' respective balance sheets. AEP pays the interest on the global notes, but the Registrant Subsidiaries accrue interest for their respective share of the global borrowing and remit the interest to AEP. The accrued interest is reflected in either Accrued Interest or Other in the Current Liabilities section of the Registrant Subsidiaries' respective balance sheets. APCo, CSPCo, KPCo, OPCo, PSO, SWEPCo and TCC participated in the global borrowing arrangement during the reporting periods.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. During 2005 and 2004, AEPSC and its billings were subject to regulation by the SEC under the PUHCA of 1935. Effective February 8, 2006, the PUHCA of 2005 was enacted, which repealed the PUHCA of 1935 and transferred the regulatory responsibility from the SEC to the FERC.

Intercompany Billings

The Registrant Subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings between Registrant Subsidiaries are capitalized or expensed depending on the nature of the services rendered.

17. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries:

TCC

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 904,527	$ 208,121	1.6%	40-71	$ -	$ -	N.M.	N.M.
Distribution	1,579,498	331,297	3.3%	15-62	-	-	N.M.	N.M.
CWIP	165,979	362	N.M.	N.M.	-	-	N.M.	N.M.
Other	217,050	89,448	6.8%	N.M.	2,978	1,011	N.M.	N.M.
Total	$ 2,867,054	$ 629,228			$ 2,978	$ 1,011		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 817,351	$ 204,426	2.1%	40-71	$ -	$ -	N.M.	N.M.
Distribution	1,476,683	332,143	3.4%	15-62	-	-	N.M.	N.M.
CWIP	129,800	1,147	N.M.	N.M.	-	-	N.M.	N.M.
Other	229,893	97,196	6.5%	N.M.	3,468	1,166	2.9%	N.M.
Total	$ 2,653,727	$ 634,912			$ 3,468	$ 1,166		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Transmission	2.3%	35-60	N.M.	N.M.
Distribution	3.4%	25-60	N.M.	N.M.
Other	6.5%	N.M.	2.9%	N.M.

TNC

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 290,485	$ 112,591	9.2%	20-49
Transmission	327,845	100,822	2.9%	40-75	-	-	N.M.	N.M.
Distribution	512,265	151,805	3.2%	19-55	-	-	N.M.	N.M.
CWIP	36,579	(1,457)	N.M.	N.M.	2,268	-	N.M.	N.M.
Other	99,411	64,713	9.3%	N.M.	60,040	58,487	N.M.	N.M.
Total	$ 976,100	$ 315,883			$ 352,793	$ 171,078		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 288,934	$ 117,963	2.6%	20-49
Transmission	289,029	98,630	3.0%	40-75	-	-	N.M.	N.M.
Distribution	492,878	144,465	3.2%	19-55	-	-	N.M.	N.M.
CWIP	42,929	(327)	N.M.	N.M.	3,495	-	N.M.	N.M.
Other	109,264	60,376	9.7%	N.M.	58,585	57,412	4.9%	N.M.
Total	$ 934,100	$ 303,144			$ 351,014	$ 175,375		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Production	N.M.	N.M.	2.6 %	20-49
Transmission	3.0%	40-75	N.M.	N.M.
Distribution	3.2%	19-55	N.M.	N.M.
Other	8.4%	N.M.	4.9%	N.M.

APCo

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,320,507	$ 697,275	2.6%	40-121	$ 1,524,296	$ 604,290	2.6%	40-121
Transmission	1,620,512	457,129	1.8%	25-87	-	-	N.M.	N.M.
Distribution	2,237,887	562,672	3.3%	11-52	-	-	N.M.	N.M.
CWIP	500,641	(7,263)	N.M.	N.M.	456,985	(5,054)	N.M.	N.M.
Other	305,811	154,829	7.7%	24-55	33,639	12,412	N.M.	N.M.
Total	$ 5,985,358	$ 1,864,642			$ 2,014,920	$ 611,648		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,140,438	$ 515,967	2.9%	40-120	$ 1,657,719	$ 748,739	2.9%	40-120
Transmission	1,266,855	481,978	2.2%	35-65	-	-	N.M.	N.M.
Distribution	2,141,153	655,856	3.2%	10-60	-	-	N.M.	N.M.
CWIP	481,579	(4,844)	N.M.	N.M.	166,059	(5,210)	N.M.	N.M.
Other	289,924	119,178	9.3%	N.M.	33,234	13,191	3.2%	N.M.
Total	$ 5,319,949	$ 1,768,135			$ 1,857,012	$ 756,720		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	2.8%	40-120	2.8%	40-120
Transmission	2.2%	35-65	N.M.	N.M.
Distribution	3.3%	10-60	N.M.	N.M.
Other	9.4%	N.M.	3.2%	N.M.

CSPCo

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,896,073	$ 812,541	3.1%	40-59
Transmission	479,119	202,585	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,475,758	514,042	3.5%	12-56	-	-	N.M.	N.M.
CWIP	77,484	(4,749)	N.M.	N.M.	216,654	704	N.M.	N.M.
Other	168,911	83,782	8.7%	N.M.	22,192	2,138	N.M.	N.M.
Total	$ 2,201,272	$ 795,660			$ 2,134,919	$ 815,383		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,874,652	$ 759,789	3.1%	40-59
Transmission	457,937	192,282	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,380,722	475,669	3.6%	12-56	-	-	N.M.	N.M.
CWIP	69,800	(3,781)	N.M.	N.M.	59,446	63	N.M.	N.M.
Other	161,205	73,505	10.2%	N.M.	22,891	3,331	N.M.	N.M.
Total	$ 2,069,664	$ 737,675			$ 1,956,989	$ 763,183		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	2.9%	40-50
Transmission	2.3%	33-50	N.M.	N.M.
Distribution	3.6%	12-56	N.M.	N.M.
Other	10.3%	N.M.	N.M.	N.M.

OPCo

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,413,340	$ 1,925,883	2.8%	35-61
Transmission	1,030,934	420,748	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,322,103	356,629	3.9%	12-55	-	-	N.M.	N.M.
CWIP	82,615	(1,115)	N.M.	N.M.	1,257,016	6,666	N.M.	N.M.
Other	238,456	117,946	9.2%	N.M.	61,181	9,827	N.M.	N.M.
Total	$ 2,674,108	$ 894,208			$ 5,731,537	$ 1,942,376		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,278,553	$ 1,876,732	2.8%	35-61
Transmission	1,002,255	403,260	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,258,518	338,652	3.9%	12-55	-	-	N.M.	N.M.
CWIP	66,103	(1,361)	N.M.	N.M.	624,065	1,494	N.M.	N.M.
Other	234,569	110,743	10.7%	N.M.	59,225	9,379	3.0%	N.M.
Total	$ 2,561,445	$ 851,294			$ 4,961,843	$ 1,887,605		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	2.8%	35-42
Transmission	2.3%	27-70	N.M.	N.M.
Distribution	4.0%	12-55	N.M.	N.M.
Other	10.1%	N.M.	3.0%	N.M.

SWEPCo

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 949,867	$ 596,453	3.1%	30-57	$ 626,333	$ 393,295	3.1%	30-57
Transmission	668,008	213,618	2.5%	40-55	-	-	N.M.	N.M.
Distribution	1,228,948	375,659	3.1%	16-65	-	-	N.M.	N.M.
CWIP	169,700	(5,709)	N.M.	N.M.	89,962	(403)	N.M.	N.M.
Other	361,138	119,361	8.6%	N.M.	234,291	141,871	N.M.	N.M.
Total	$ 3,377,661	$ 1,299,382			$ 950,586	$ 534,763		

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 912,044	$ 577,611	3.1%	30-57	$ 601,392	$ 483,743	3.1%	30-57
Transmission	645,297	201,521	2.5%	40-55	-	-	N.M.	N.M.
Distribution	1,153,026	339,258	3.1%	16-65	-	-	N.M.	N.M.
CWIP	81,437	(73)	N.M.	N.M.	22,738	667	N.M.	N.M.
Other	362,572	134,575	8.6%	N.M.	228,133	38,914	N.M.	N.M.
Total	$ 3,154,376	$ 1,252,892			$ 852,263	$ 523,324		

2004	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.3%	30-57	3.3%	30-57
Transmission	2.8%	40-55	N.M.	N.M.
Distribution	3.6%	16-65	N.M.	N.M.
Other	6.9%	N.M.	N.M.	N.M.

2006	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
	(in thousands)			**(in years)**	**(in thousands)**			**(in years)**
Production	$ 686,776	$ 395,736	3.6%	31	$ 478,955	$ 161,172	3.8%	40-50
Transmission	-	-	N.M.	N.M.	394,419	124,709	1.7%	25-75
Distribution	-	-	N.M.	N.M.	481,083	138,578	3.4%	11-75
CWIP	15,198	942	N.M.	N.M.	29,587	(1,785)	N.M.	N.M.
Other	2,415	1,744	11.5%	N.M.	55,544	19,918	9.6%	N.M.
Total	$ 704,389	$ 398,422			$ 1,439,588	$ 442,592		

	AEGCo Nonregulated				KPCo Nonregulated			
Functional Class of Property	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
	(in thousands)			**(in years)**	**(in thousands)**			**(in years)**
Other	$ 45	$ -	N.M.	N.M.	$ 5,545	$ 186	N.M	N.M.

2005	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
	(in thousands)			**(in years)**	**(in thousands)**			**(in years)**
Production	$ 684,721	$ 379,641	3.5%	31	$ 472,575	$ 151,389	3.8%	40-50
Transmission	-	-	N.M.	N.M.	386,945	119,048	1.7%	25-75
Distribution	-	-	N.M.	N.M.	456,063	136,106	3.5%	11-75
CWIP	12,252	2,226	N.M.	N.M.	35,461	(1,126)	N.M.	N.M.
Other	2,251	1,058	16.0%	N.M.	57,776	20,241	9.4%	N.M.
Total	$ 699,224	$ 382,925			$ 1,408,820	$ 425,658		

	AEGCo Nonregulated				KPCo Nonregulated			
Functional Class of Property	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
	(in thousands)			**(in years)**	**(in thousands)**			**(in years)**
Other	$ 118	$ -	N.M.	N.M.	$ 5,606	$ 159	2.0%	N.M.

2004	AEGCo Regulated		KPCo Regulated	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
		(in years)		**(in years)**
Production	3.5%	31	3.8%	40-50
Transmission	N.M.	N.M.	1.7%	25-75
Distribution	N.M.	N.M.	3.5%	11-75
Other	16.4%	N.M.	9.2%	N.M.

2006

Functional Class of Property	I&M Regulated Property, Plant and Equipment (in thousands)	I&M Regulated Accumulated Depreciation (in thousands)	I&M Regulated Annual Composite Depreciation Rate	I&M Regulated Depreciable Life Ranges (in years)	PSO Regulated Property, Plant and Equipment (in thousands)	PSO Regulated Accumulated Depreciation (in thousands)	PSO Regulated Annual Composite Depreciation Rate	PSO Regulated Depreciable Life Ranges (in years)
Production	$ 3,363,813	$ 1,948,199	3.6%	40-119	$ 1,091,910	$ 638,599	2.7%	30-57
Transmission	1,047,264	420,256	1.9%	30-65	503,638	158,115	2.0%	40-75
Distribution	1,102,033	355,059	4.0%	12-65	1,215,236	269,306	3.0%	25-65
CWIP	183,893	(11,627)	N.M.	N.M.	141,283	(8,252)	N.M.	N.M.
Other	373,983	94,183	10.2%	N.M.	229,759	129,339	6.7%	N.M.
Total	$ 6,070,986	$ 2,806,070			$ 3,181,826	$ 1,187,107		

Functional Class of Property	I&M Nonregulated Property, Plant and Equipment (in thousands)	I&M Nonregulated Accumulated Depreciation (in thousands)	I&M Nonregulated Annual Composite Depreciation Rate	I&M Nonregulated Depreciable Life Ranges (in years)	PSO Nonregulated Property, Plant and Equipment (in thousands)	PSO Nonregulated Accumulated Depreciation (in thousands)	PSO Nonregulated Annual Composite Depreciation Rate	PSO Nonregulated Depreciable Life Ranges (in years)
Other	$ 155,744	$ 108,061	N.M.	N.M.	$ 4,468	$ -	N.M.	N.M.

2005

Functional Class of Property	I&M Regulated Property, Plant and Equipment (in thousands)	I&M Regulated Accumulated Depreciation (in thousands)	I&M Regulated Annual Composite Depreciation Rate	I&M Regulated Depreciable Life Ranges (in years)	PSO Regulated Property, Plant and Equipment (in thousands)	PSO Regulated Accumulated Depreciation (in thousands)	PSO Regulated Annual Composite Depreciation Rate	PSO Regulated Depreciable Life Ranges (in years)
Production	$ 3,128,078	$ 1,901,698	3.8%	40-119	$ 1,072,928	$ 639,256	2.7%	30-57
Transmission	1,028,496	401,024	1.9%	30-65	479,272	153,998	2.1%	40-75
Distribution	1,029,498	335,642	4.1%	12-65	1,140,535	262,763	3.1%	25-65
CWIP	311,080	(1,544)	N.M.	N.M.	90,455	(7,798)	N.M.	N.M.
Other	309,217	79,741	11.7%	N.M.	207,211	127,639	7.4%	N.M.
Total	$ 5,806,369	$ 2,716,561			$ 2,990,401	$ 1,175,858		

Functional Class of Property	I&M Nonregulated Property, Plant and Equipment (in thousands)	I&M Nonregulated Accumulated Depreciation (in thousands)	I&M Nonregulated Annual Composite Depreciation Rate	I&M Nonregulated Depreciable Life Ranges (in years)	PSO Nonregulated Property, Plant and Equipment (in thousands)	PSO Nonregulated Accumulated Depreciation (in thousands)	PSO Nonregulated Annual Composite Depreciation Rate	PSO Nonregulated Depreciable Life Ranges (in years)
Other	$ 155,913	$ 105,997	3.4%	N.M.	$ 4,594	$ -	N.M.	N.M.

2004

Functional Class of Property	I&M Regulated Annual Composite Depreciation Rate	I&M Regulated Depreciable Life Ranges (in years)	PSO Regulated Annual Composite Depreciation Rate	PSO Regulated Depreciable Life Ranges (in years)
Production	3.7%	40-119	2.7%	30-57
Transmission	1.9%	30-65	2.3%	40-75
Distribution	4.1%	12-65	3.3%	25-65
Other	11.2%	N.M.	7.9%	N.M.

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.66, $0.66 and $0.65 per ton in 2006, 2005 and 2004, respectively.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are charged to accumulated depreciation. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal cost is expensed as incurred (see “Accounting for Asset Retirement Obligations” section of this note).

Accounting for Asset Retirement Obligations (ARO)

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is followed for regulated and nonregulated property that has a legal obligation related to asset retirement. Upon settlement of an ARO, the Registrant Subsidiaries recognize any difference between the ARO liability and actual costs as income or expense.

The Registrant Subsidiaries adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

The Registrant Subsidiaries completed a review of their FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In 2005, the Registrant Subsidiaries recorded conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to regulated operations was generally charged to a regulatory liability and reflected in Regulatory Liabilities and Deferred Investment Tax Credits on the balance sheets of certain Registrant Subsidiaries. The Registrant Subsidiaries with nonregulated generation operations recorded an unfavorable cumulative effect related to asbestos removal for those operations. This adjustment is reflected in Cumulative Effect of Accounting Change, Net of Tax on certain Registrant Subsidiaries’ 2005 statements of income.

The following table shows the liability for conditional ARO and cumulative effect recorded in 2005 for FIN 47 by Registrant Subsidiary:

	Liability	Cumulative Effect	
	Recorded	Pretax	Net of Tax
Company	(in thousands)		
AEGCo	$ 56	$ -	$ -
APCo	8,972	(3,470)	(2,256)
CSPCo	1,981	(1,292)	(839)
I&M	5,801	-	-
KPCo	1,190	-	-
OPCo	9,513	(7,039)	(4,575)
PSO	6,056	-	-
SWEPCo	6,702	(1,926)	(1,252)
TCC	1,165	-	-
TNC	13,514	(13,034)	(8,472)

As of December 31, 2006 and 2005, I&M's ARO liability was $803 million and $731 million for nuclear decommissioning of the Cook Plant. These liabilities are reflected in Asset Retirement Obligations on I&M's Consolidated Balance Sheets. As of December 31, 2006 and 2005, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $974 million and $870 million, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's Consolidated Balance Sheets.

The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

Pro forma net income related to the application of FIN 47 is not presented for the year ended December 31, 2004 because it is not materially different from reported net income for 2004.

The following is a summary by Registrant Subsidiary of the pro forma liability for conditional ARO calculated as if FIN 47 had been adopted as of January 1, 2004:

Company	December 31, 2004 (in thousands)
AEGCo	$ 53
APCo	8,434
CSPCo	1,862
I&M	5,453
KPCo	1,119
OPCo	8,943
PSO	5,693
SWEPCo	6,757
TCC	1,085
TNC	12,704

The following is a reconciliation of the 2006 and 2005 aggregate carrying amounts of ARO by Registrant Subsidiary:

Company	ARO at January 1, 2006	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2006
			(in thousands)			
AEGCo (a) (e)	$ 1,370	$ 107	$ -	$ (173)	$ -	$ 1,304
APCo (a) (e)	35,496	2,620	307	(1,422)	505	37,506
CSPCo (a) (e)	17,844	1,310	304	(891)	1,036	19,603
I&M (a) (b) (e)	737,959	48,806	-	(507)	23,595	809,853
KPCo (e)	1,190	74	-	(89)	-	1,175
OPCo (a) (e)	65,557	4,949	-	(2,295)	3,108	71,319
PSO (e)	6,056	382	-	(188)	187	6,437
SWEPCo (a) (c) (e) (f)	43,077	2,437	8,362	(6,581)	723	48,018
TCC (e)	1,165	74	-	-	-	1,239
TNC (e)	13,514	862	-	(33)	525	14,868

Company	ARO at January 1, 2005, Including Held for Sale	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2005
			(in thousands)			
AEGCo (a)(e)	$ 1,216	$ 98	$ 56	$ -	$ -	$ 1,370
APCo (a)(e)	24,626	1,928	8,972	(32)	2	35,496
CSPCo (a)(e)	11,585	864	1,981	(9)	3,423	17,844
I&M (a)(b)(e)	711,769	47,368	5,801	-	(26,979)	737,959
KPCo (e)	-	-	1,190	-	-	1,190
OPCo (a)(e)	45,606	3,665	9,513	-	6,773	65,557
PSO (e)	-	-	6,056	-	-	6,056
SWEPCo (a)(c)(e)(f)	27,361	1,491	18,071	(3,449)	(397)	43,077
TCC (d)(e)	248,872	7,549	1,165	(256,421)	-	1,165
TNC (e)	-	-	13,514	-	-	13,514

(a) Includes ARO related to ash ponds.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant ($803 million and $731 million at December 31, 2006 and 2005, respectively).
(c) Includes ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC.
(d) Includes ARO related to nuclear decommissioning costs for TCC's share of STP. STP was sold in May 2005 (see Note 8).
(e) Includes ARO related to asbestos removal.
(f) The current portion of SWEPCo's ARO, totaling $1 million and $2 million, at December 31, 2006 and 2005, respectively, is included in Other in the Current Liabilities section of SWEPCo's Consolidated Balance Sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on the Registrant Subsidiaries' Consolidated Statements of Income for 2006, 2005 and 2004 were as follows:

Company	2006	2005	2004
		(in millions)	
AEGCo	$ -	$ 0.1	$ -
APCo	12.0	8.0	6.6
CSPCo	1.9	1.6	1.1
I&M	7.9	4.5	2.3
KPCo	0.2	0.3	0.3
OPCo	2.6	1.4	1.5
PSO	0.7	0.9	0.3
SWEPCo	1.3	2.4	0.8
TCC	2.7	1.0	1.2
TNC	0.9	0.7	0.4

The amounts of interest capitalized included in Interest Expense on the Registrant Subsidiaries' Consolidated Statements of Income for 2006, 2005 and 2004 were as follows:

Company	2006	2005	2004
		(in millions)	
AEGCo	$ 0.4	$ 0.2	$ -
APCo	17.7	8.7	8.1
CSPCo	6.0	1.5	5.0
I&M	7.5	4.3	1.8
KPCo	0.7	0.3	0.2
OPCo	42.7	16.4	4.8
PSO	1.5	0.6	0.3
SWEPCo	2.2	1.2	0.3
TCC	2.6	1.5	0.7
TNC	0.6	0.4	0.2

Jointly-owned Electric Utility Plant

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly-owned with affiliated and nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

Company	Fuel Type	Percent of Ownership	Company's Share at December 31, 2006 Utility Plant in Service	Construction Work in Progress (i)	Accumulated Depreciation
				(in thousands)	
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 15,702	$ 280	$ 7,560
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85,253	31,691	49,150
J.M. Stuart Generating Station (c)	Coal	26.0	284,142	101,769	127,591
Wm. H. Zimmer Generating Station (a)	Coal	25.4	751,148	4,797	302,053
Transmission	N/A	(d)	62,876	86	42,433
Total			$ 1,199,121	$ 138,623	$ 528,787
PSO					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	15.6 %	$ 86,676	$ 543	$ 55,951
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	$ 240,471	$ 5,248	$ 166,938
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0	96,799	1,637	57,303
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9	481,093	4,847	310,271
Total			$ 818,363	$ 11,732	$ 534,512
TCC (h)					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	7.8 %	$ 39,660	$ -	$ 19,671
TNC					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	54.7 %	$ 290,485	$ 2,164	$ 124,459

Company	Fuel Type	Percent of Ownership	Company's Share at December 31, 2005 — Utility Plant in Service	Construction Work in Progress (i)	Accumulated Depreciation
				(in thousands)	
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 15,681	$ 52	$ 7,274
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85,162	7,583	48,086
J.M. Stuart Generating Station (c)	Coal	26.0	266,136	35,461	120,770
Wm. H. Zimmer Generating Station (a)	Coal	25.4	749,112	2,295	280,310
Transmission	N/A	(d)	62,553	1,344	41,109
Total			$ 1,178,644	$ 46,735	$ 497,549
PSO					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	15.6 %	$ 86,051	$ 700	$ 54,401
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	$ 237,941	$ 3,829	$ 159,774
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0	94,261	2,494	55,378
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9	459,513	10,447	297,590
Total			$ 791,715	$ 16,770	$ 512,742
TCC (h)					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	7.8 %	$ 39,656	$ 321	$ 19,765
TNC					
Oklaunion Generating Station (Unit No. 1) (e)	Coal	54.7 %	$ 288,934	$ 2,165	$ 117,963

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO.
(f) Operated by Cleco Corporation, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Included in Assets Held for Sale – Texas Generation Plant on TCC's Consolidated Balance Sheets.
(i) Primarily relates to environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each Registrant Subsidiary is provided below. In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors.

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2006					
Operating Revenues	$ 78,151	$ 634,441	$ 428,768	$ 515,779	$ 151,847
Operating Income	4,220	138,473	92,497	103,438	22,524
Net Income	2,928	73,594	51,337	57,878	9,830
June 30, 2006					
Operating Revenues	$ 77,195	$ 514,588	$ 417,109	$ 469,454	$ 135,303
Operating Income	2,998	30,601	61,331	57,461	13,554
Net Income	2,220	9,647	32,262	28,525	5,051
September 30, 2006					
Operating Revenues	$ 74,756	$ 648,601	$ 539,898	$ 525,535	$ 152,319
Operating Income	3,110	89,716	140,636	66,401	21,846
Net Income	2,219	30,536	84,021	34,561	9,869
December 31, 2006					
Operating Revenues	$ 79,712	$ 596,398	$ 420,960	$ 466,179	$ 146,398
Operating Income	2,590	106,853	43,186	24,891	23,701
Net Income	3,547	67,672	17,959	204	10,285

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2006					
Operating Revenues	$ 702,606	$ 354,729	$ 305,132	$ 135,288	$ 74,666
Operating Income (Loss)	157,063	(1,163)	38,960	11,468	8,635
Net Income (Loss)	95,032	(5,357)	17,872	3,773	3,834
June 30, 2006					
Operating Revenues	$ 616,007	$ 347,046	$ 359,484	$ 161,489	$ 82,998
Operating Income	53,069	30,024	54,932	33,411	184
Net Income (Loss)	23,399	14,638	28,312	16,975	(592)
September 30, 2006					
Operating Revenues	$ 764,908	$ 458,441	$ 456,700	$ 173,923	$ 87,762
Operating Income	145,100	77,577	91,273	35,771	16,368
Net Income	83,342	42,023	49,706	17,235	8,446
December 31, 2006					
Operating Revenues	$ 641,354	$ 281,568	$ 310,523	$ 193,964	$ 84,044
Operating Income (Loss)	70,059	(15,445)	4,453	48,447	10,100
Net Income (Loss)	26,870	(14,444)	(4,167)	3,586	3,255

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2005					
Operating Revenues	$ 66,546	$ 557,695	$ 367,133	$ 457,559	$ 128,060
Operating Income	3,195	92,359	78,667	72,890	21,083
Income Before Cumulative Effect of Accounting Changes	2,516	46,672	47,468	39,669	9,885
Net Income	2,516	46,672	47,468	39,669	9,885
June 30, 2005					
Operating Revenues	$ 65,082	$ 497,102	$ 359,990	$ 457,560	$ 122,709
Operating Income	2,340	53,752	63,558	69,589	9,743
Income Before Cumulative Effect of Accounting Changes	2,073	24,213	34,651	35,593	2,446
Net Income	2,073	24,213	34,651	35,593	2,446
September 30, 2005					
Operating Revenues	$ 69,640	$ 570,122	$ 454,568	$ 515,079	$ 143,996
Operating Income	2,913	79,477	65,604	100,754	18,223
Income Before Cumulative Effect of Accounting Changes	2,239	37,372	34,225	53,012	7,727
Net Income	2,239	37,372	34,225	53,012	7,727
December 31, 2005					
Operating Revenues	$ 69,487	$ 551,354	$ 360,641	$ 462,404	$ 136,578
Operating Income	2,453	57,800	35,051	43,427	11,782
Income Before Cumulative Effect of Accounting Changes	1,867	27,575	21,455	18,578	751
Net Income	1,867	25,319	20,616	18,578	751

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2005					
Operating Revenues	$ 655,154	$ 253,082	$ 247,211	$ 201,357	$ 118,907
Operating Income	151,434	7,113	29,163	30,284	15,815
Income Before Cumulative Effect of Accounting Changes	99,483	505	12,205	1,137	7,394
Net Income	99,483	505	12,205	1,137	7,394
June 30, 2005					
Operating Revenues	$ 650,999	$ 286,602	$ 332,851	$ 202,326	$ 114,704
Operating Income	123,901	32,435	37,363	42,922	20,162
Income Before Cumulative Effect of Accounting Changes	71,481	18,570	19,304	28,368	12,004
Net Income	71,481	18,570	19,304	28,368	12,004
September 30, 2005					
Operating Revenues	$ 687,140	$ 432,633	$ 474,283	$ 203,365	$ 126,097
Operating Income	99,437	85,387	88,135	63,399	36,924
Income Before Cumulative Effect of Accounting Changes	56,408	48,654	49,731	40,476	22,304
Net Income	56,408	48,654	49,731	40,476	22,304
December 31, 2005					
Operating Revenues	$ 641,256	$ 331,761	$ 351,034	$ 186,198	$ 99,180
Operating Income (Loss)	50,715	(6,919)	5,876	40,676	3,798
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	23,047	(9,836)	(6,050)	(19,209)	(226)
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	-	-	-	(224,551)	-
Net Income (Loss)	18,472	(9,836)	(7,302)	(243,760)	(8,698)

(a) See “Extraordinary Items” section of Note 2 and “TCC Texas Restructuring” section of Note 4 for discussions of the extraordinary loss booked in the fourth quarter of 2005.

For each of the Registrant Subsidiaries, (excluding TCC for 2005) there were no significant, nonrecurring events in the fourth quarter of 2006 or 2005.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the Registrant Subsidiaries through intercompany notes. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The Registrant Subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from AEP.

Dividend Restrictions

Under regulatory orders, the Registrant Subsidiaries can only pay dividends out of retained or current earnings.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. AEP does not have an ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's sale of receivables agreement expires August 24, 2007. AEP intends to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2006, $536 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent receivables purchased by AEP Credit from certain Registrant Subsidiaries. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit.

Budgeted Capital Expenditures

Construction expenditures for the Registrant Subsidiaries for 2007 are:

Company	Projected Construction Expenditures (in millions)
AEGCo	$ 18
APCo	664
CSPCo	337
I&M	252
KPCo	71
OPCo	832
PSO	319
SWEPCo	537
TCC	241
TNC	143

In addition, AEGCo and CSPCo announced the purchase of gas-fired generating units for $325 million and $102 million, respectively.

Significant Factors

Ohio New Generation

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 629 MW IGCC power plant using clean-coal technology. The application proposed cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs through regulatory authorization until the plant is placed in service. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSPs. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover or refund in distribution rates any difference between the Ohio companies' 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 costs. Through December 31, 2006, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each recovered $6 million of those costs. The PUCO indicated that if the Ohio companies have not commenced continuous construction of the IGCC plant by 2010, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

SECA Revenue Subject to Refund

The AEP East companies eliminated through-and-out transmission service (T&O) revenues in accordance with FERC orders and implemented SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. The AEP East companies have reached settlements with certain customers related to approximately $70 million of such revenues. The unsettled gross SECA revenues total approximately $150 million. If the ALJ's initial decision is upheld in its entirety, it would disallow $126 million of the AEP East companies' unsettled gross SECA revenues. The AEP East companies have provided a reserve for $37 million in net refunds.

AEP, together with Exelon and the Dayton Power and Light Company, filed an extensive post hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it is contrary to prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. However, the initial decision is adversely impacting settlement negotiations. Although management believes it has meritorious arguments, they cannot predict the ultimate outcome of any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision, it will have an adverse effect on future results of operations and cash flows.

Pension and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS 158 related to phase one of its pension and postretirement benefit accounting project. The new standard requires the recognition of a liability for 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. The adoption during the fourth quarter of 2006 resulted in a negative impact on certain Registrant Subsidiaries' common equity at December 31, 2006 due to the recognition of an accumulated other comprehensive income reduction for those jurisdictions where we could not record a regulatory asset.

AEP maintains qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans collectively the Pension Plans. Additionally, AEP entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. AEP also sponsors other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic benefit cost and assumed rate of return on Plan assets for AEP's Pension Plans and Postretirement Plans:

	Year Ended December 31,		
	2006	**2005**	**2004**
Net Periodic Benefit Cost		**(in millions)**	
Pension Plans	$ 71	$ 61	$ 40
Postretirement Plans	96	109	141
Assumed Rate of Return			
Pension Plans	8.50%	8.75%	8.75%
Postretirement Plans	8.00%	8.37%	8.35%

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as its ten-year average return, for the period ended December 2006, of approximately 9.43%. AEP anticipates that the investment managers employed for the Pension Plans will continue to generate long-term returns averaging 8.50%.

The expected long-term rate of return on the Plans' assets is based on AEP's targeted asset allocation and its expected investment returns for each investment category. AEP's assumptions are summarized in the following table:

	Pension		Other Postretirement Benefit Plans		
	2006 Actual Asset Allocation	2007 Target Asset Allocation	2006 Actual Asset Allocation	2007 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	63%	65%	66%	65%	10.00%
Real Estate	6%	5%	-%	-%	8.25%
Fixed Income	26%	28%	32%	33%	5.25%
Cash and Cash Equivalents	5%	2%	2%	2%	4.25%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation. AEP believes that 8.50% and 8.00% for the Pension Plans and Postretirement Plans, respectively, are reasonable long-term rate of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 12.78% and 7.76% for the twelve months ended December 31, 2006 and 2005, respectively. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2006, AEP had cumulative gains of approximately $187 million, which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2006 under this method was 5.75% for the Pension Plans and 5.85% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 8.50%, a discount rate of 5.75% and various other assumptions, AEP estimates that the pension costs for all pension plans will approximate $40 million, $14 million and $5 million in 2007, 2008 and 2009, respectively. Based on an expected rate of return on the OPEB plans' assets of 8.00%, a discount rate of 5.85% and various other assumptions, AEP estimates Postretirement Plan costs will approximate $85 million, $81 million and $78 million in 2007, 2008 and 2009, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Combined Management's Discussion and Analysis of Registrant Subsidiaries.

The value of AEP's Pension Plans' assets increased to $4.3 billion at December 31, 2006 from $4.1 billion at December 31, 2005 primarily due to investment returns on the assets. The Qualified Plans paid $267 million in benefits to plan participants during 2006 (nonqualified plans paid $9 million in benefits). The value of AEP's

Postretirement Plans' assets increased to $1.3 billion at December 31, 2006 from $1.2 billion at December 31, 2005. The Postretirement Plans paid $112 million in benefits to plan participants during 2006.

AEP's nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation in excess of plan assets was $78 million and $81 million at December 31, 2006 and 2005, respectively. AEP made a contribution of $626 million in 2005 to meet its goal of fully funding all Qualified Plans by the end of 2005. AEP's Qualified Plans remained fully funded as of December 31, 2006.

Certain pension plans AEP sponsors and maintains contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. AEP believes that its defined benefit pension plans comply with the applicable requirements of such laws.

The Pension Protection Act of 2006 did not materially impact AEP's plans.

Litigation

See discussion of the Environmental Litigation under "Environmental Matters."

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

<u>Environmental Matters</u>

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring 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; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants.

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. Management also monitors possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change. All of these matters are discussed below.

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. The states implement and administer many of these programs and could impose additional or more stringent requirements.

<u>National Ambient Air Quality Standards:</u> 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 safety margin. 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 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 submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements 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 affirmed certain aspects of the final CAIR after reconsideration. The rule has been challenged in the courts. States were required to 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.

<u>Hazardous Air Pollutants:</u> 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 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 affirmed certain aspects of the final CAMR after reconsideration, and the rule has been challenged in the courts. States were required to develop and submit their SIPs to implement CAMR by November 2006.

<u>The Acid Rain Program:</u> 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 NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and states to use it as a model for other emission reduction programs, including CAIR and CAMR. The Registrant Subsidiaries continue to 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.

<u>Regional Haze</u>: 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 of visibility in these areas (the "Regional Haze" program). In 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 CAIR will result in more visibility improvements than BART for power plants subject to it. 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 courts upheld the final rule.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above will require significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and are not incorporated into SIPs. As a result, these rules may be further modified. Management's estimates 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, and the actual costs to comply could differ significantly from the estimates discussed below.

APCo, CSPCo, KPCo and OPCo installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at their power plants over the past several years to comply with NO_x requirements in various SIPs. The Registrant Subsidiaries comply with Acid Rain Program SO_2 requirements by installing scrubbers, using alternate fuels and using SO_2 allowances. They receive allowances through Acid Rain Program allocations and purchase them at the annual Federal EPA auction or in the market. Decreasing allowance allocations, diminishing SO_2 allowance banks, and increasing allowance costs will require installation of additional controls on the Registrant Subsidiaries' power plants. In addition under CAIR and CAMR, the Registrant Subsidiaries will be required to install additional controls by 2010. The Registrant Subsidiaries plan to install additional scrubbers on 7,300 MW for SO_2 control and additional SCRs on 1,900 MW for NO_x control to comply with current CAIR and CAMR requirements. In January 2007, the scrubber on Unit 2 of Mitchell Plant went into service leaving 6,500 MW of scrubbers to be completed. From 2007 to 2011, the following table shows the total estimated costs for environmental investment and additional scrubbers and other SO_2 equipment by Registrant Subsidiary:

Company	Total Environmental	Cost of Additional Scrubbers and SO_2 Equipment
	(in millions)	
APCo	$ 739	$ 494
CSPCo	299	187
OPCo	746	502
PSO	263	221
SWEPCo	66	9

The Registrant Subsidiaries will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, the Registrant Subsidiaries expect to incur additional costs for pollution control technology retrofits totaling approximately $2.6 billion between 2012 and 2020. However, this estimate is highly uncertain due to the uncertainty associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on each unit; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. Management cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

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.

Clean Water Act Regulation

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for the Registrant Subsidiaries' plants. Any capital costs incurred to meet these standards had been expected to be incurred between 2008 and 2010. The Registrant Subsidiaries undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. In addition, a recent court decision introduced additional uncertainty to these costs and their timing. The following table shows the investment amount per Registrant Subsidiary.

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

The rule was challenged in the courts by states, advocacy organizations and industry. On January 25, 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. Among other things, the restoration option, the cost-benefit and other tests and certain alternative technology options in the 2004 rule have been remanded. Management cannot predict how or when the Federal EPA will respond to the remand, or what effect the remand may have on similar requirements adopted by the states. The Registrant Subsidiaries may seek further review or relief from the schedules included in the final rule and their plant's permits, in order to allow time for the Federal EPA's response to the remand.

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 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 1998, but the treaty was not submitted to the Senate for its advice and consent. In 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. Members of Congress introduced several bills seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none have passed. The AEP System participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

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 upheld by an appellate court. The U.S. Supreme Court reviewed the appellate decision and is expected to issue its decision in 2007.

The Registrant Subsidiaries will seek recovery of expenditures for potential regulation of CO_2 emissions from customers through regulated rates (in regulated jurisdictions). The Registrant Subsidiaries should be able to recover these expenditures through market prices in deregulated jurisdictions.

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 thereafter against 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 were resolved through consent decrees. The alleged modifications at the Registrant Subsidiaries' power plants occurred over a twenty-year period. A bench trial on the liability issues was held during 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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 have reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted 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. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that would excluded most of the challenged activities from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, 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 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 manage other environmental concerns that are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and
- changes in the estimate or different estimates that could have been selected could have a material effect on results of operations or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

The sections that follow present information about the Registrant Subsidiaries' most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required: The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, AEGCo and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC) reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrant Subsidiaries recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation by matching the timing of expense recognition with the recovery of such expense in regulated revenues. Likewise, they match income with the regulated revenues from their customers in the same accounting period. Regulatory liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When regulatory assets are probable of recovery through regulated rates, the Registrant Subsidiaries record them as assets on the balance sheet. Regulatory assets are tested for probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on the results of operations. Refer to Note 5 of the Notes to Financial Statements of Registrant Subsidiaries for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: The Registrant Subsidiaries record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Incremental unbilled electric utility revenues included in Revenue for the years ended December 31 were as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
Company		**(in thousands)**	
APCo	$ 711	$ 14,024	$ 18,206
CSPCo	4,545	(5,404)	283
I&M	1,166	1,783	(2,942)
KPCo	1,021	1,105	3,833
OPCo	(3,312)	14,689	(2,793)
PSO	157	494	2,789
SWEPCo	(4,875)	606	1,814
TCC	(14,262)	(164)	(1,579)
TNC	(2,740)	1,250	(1,160)

Assumptions and Approach Used: The Registrant Subsidiaries calculate the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required: Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used: APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided for in the original documentation related to hedge accounting.

Effect if Different Assumptions Used: There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required: In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Registrant Subsidiaries evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, the subsidiary records an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For nonregulated assets, any impairment charge is recorded as a charge against earnings.

Assumptions and Approach Used: The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrant Subsidiaries estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. In cases of impairment as described in Note 8 of the Notes to Financial Statements of Registrant Subsidiaries, the best estimate of fair value was made using valuation methods based on the most current information at that time. Certain Registrant Subsidiaries have been divesting certain generation assets and their sales values can vary from the recorded fair value as described in Note 8 of the Notes to Financial Statements of Registrant Subsidiaries. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required: APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under SFAS 87, "Employers' Accounting For Pensions", SFAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" and SFAS 158. See Note 9 of the Notes to Financial Statements of Registrant Subsidiaries for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used: The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Expected return on plan assets
- Health care cost trend rate
- Rate of compensation increase
- Cash balance crediting rate

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2006 Benefit Obligations:				
Discount Rate	$ (178.2)	$ 192.7	$ (114.1)	$ 121.4
Compensation Increase Rate	27.2	(25.5)	3.3	(3.2)
Cash Balance Crediting Rate	13.4	16.7	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	91.7	(83.7)
Effect on 2006 Periodic Cost:				
Discount Rate	(13.0)	13.6	(10.4)	10.6
Compensation Increase Rate	5.9	(5.6)	0.6	(0.6)
Cash Balance Crediting Rate	6.7	(1.9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	15.2	(14.7)
Expected Return on Plan Assets	(19.7)	19.7	(5.6)	5.7

N/A = Not Applicable

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level and an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. Management expects that the adoption of this standard will impact MTM valuations of certain contracts, but are unable to quantify the effect at this time. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. The Registrant Subsidiaries will adopt SFAS 157 effective January 1, 2008.

In July 2006, the FASB issued FIN 48. It clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. Management estimates the effect of this interpretation on each of the Registrant Subsidiaries' financial statements will be an unfavorable adjustment to retained earnings of less than $1 million except for the following:

Company	**(in millions)**
APCo	$ 7
OPCo	3
TCC	2

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008.